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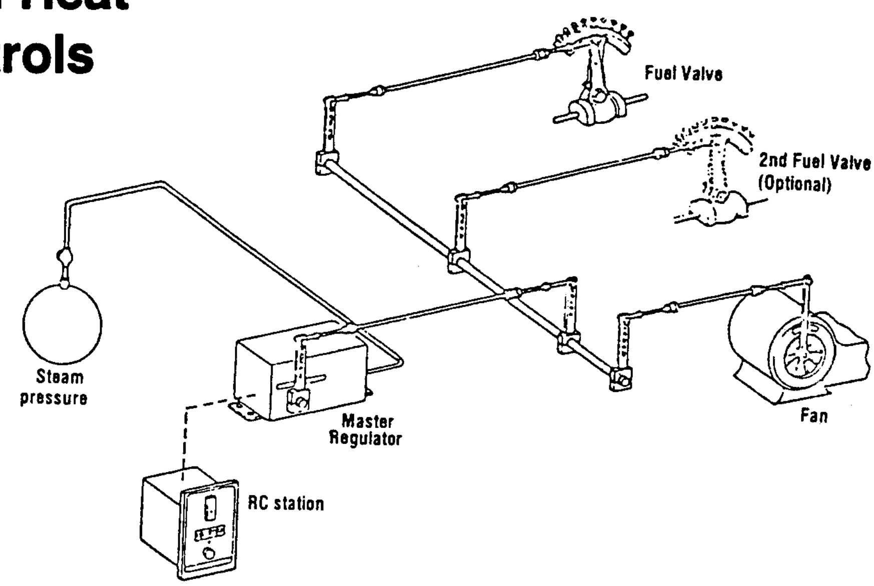
Selection Guidelines for Central Heat Plant Controls

by
Steven R. Warner
Mike C.J. Lin
Gary W. Schanche



The operation and control of Central Heating Plants (CHPs) are important factors in maintaining the readiness of U.S. Army installations. Aging CHPs often experience increased interruptions, maintenance difficulties, and inefficient operation. As fuel costs increase, there is a growing need to take advantage of new, emerging control technologies. Microprocessor-based controls can provide opportunities for increased reliability, enhanced safety, better performance monitoring, and cost reduction. However, upgraded control systems cannot compensate for a boiler in poor mechanical condition. Any proposed control systems upgrade must be preceded by a mechanical assessment of the boiler. These CHP control guidelines can help installation personnel develop budgetary-cost proposals to upgrade gas/oil-fired boiler controls for gas/oil-fired steam or high temperature hot water (HTHW) systems.

These general guidelines provide basic information to evaluate the feasibility of upgrading boiler control systems, and a methodology for developing budget proposals. Judgement is required to develop designs for specific unit and site characteristics, boiler safety codes, and local regulatory requirements. These guidelines do not eliminate the need for competent professional engineers to finalize assessments of existing conditions, to develop a plant control system design that meets existing and new requirements, and to evaluate alternative contractor proposals.

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The operation and control of Central Heating Plants (CHPs) are important factors in maintaining the readiness of U.S. Army installations. Aging CHPs often experience increased interruptions, maintenance difficulties, and inefficient operation. As fuel costs increase, there is a growing need to take advantage of new, emerging control technologies. Microprocessor-based controls can provide opportunities for increased reliability, enhanced safety, better performance monitoring, and cost reduction. However, upgraded control systems cannot compensate for a boiler in poor mechanical condition. Any proposed control systems upgrade must be preceded by a mechanical assessment of the boiler. These CHP control guidelines can help installation personnel develop budgetary-cost proposals to upgrade gas/oil-fired boiler controls for gas/oil-fired steam or high temperature hot water (HTHW) systems.

These general guidelines provide basic information to evaluate the feasibility of upgrading boiler control systems, and a methodology for developing budget proposals. Judgement is required to develop designs for specific unit and site characteristics, boiler safety codes, and local regulatory requirements. These guidelines do not eliminate the need for competent professional engineers to finalize assessments of existing conditions, to develop a plant control system design that meets existing and new requirements, and to evaluate alternative contractor proposals.

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Foreword

This study was conducted for U.S. Army Center for Public Works under Project 4A162784AT45, "Energy and Energy Conservation"; Work Unit EA-X22, "Central Plant Controls." The technical monitor was Philip Connor, CECPW-FU-M.

The work was performed by the Energy and Utility Systems Division (FE) of the Infrastructure Laboratory (FL), U.S. Army Construction Engineering Research Laboratories (USACERL). The USACERL principal investigator was Dr. Mike C.J. Lin. Gary Schanche is team leader of the Fuels and Power Systems Team (USACERL-FEP). Steven R. Warner is associated with Stanley Consultants, Inc., Muscatine, IA. Donald F. Fournier is Acting Chief, CECER-FE, and Dr. David M. Joncich is Acting Chief, CECER-FL. The USACERL technical editor was William J. Wolfe, Information Management Office.

LTC David J. Rehbein is Commander and Acting Director, USACERL, and Dr. Michael J. O'Connor is Technical Director.

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1 Introduction

Background

The operation and control of central heating plants (CHPs) are important, even critical factors in maintaining the readiness of a U.S. Army installation. However, aging CHPs are subject to interruptions, maintenance difficulties, and relatively inefficient operation. Some Department of Defense (DOD) CHPs are in danger of becoming obsolete. Certain control system components used in these older plants are no longer manufactured, and many spare parts are becoming unavailable. Increasing fuel costs underscore a growing need to upgrade these plants with more reliable automatic control systems to maintain safe, reliable, and efficient boilers.

Microprocessor-based controls can increase boiler reliability, enhance safety, monitor performance, and generally help reduce costs. However, even upgraded control systems cannot compensate for a boiler that is in poor mechanical condition. Any proposed control systems upgrade must be preceded by a mechanical assessment of the boiler. Assessments should consider boiler tubes, furnace setting, steam piping, stack, fans, pumps, fuel supply and storage, water treatment, emission controls, and electrical power equipment.

Objective

The objective of this study was to develop guidelines to help CHP operating foremen and Army District Staff Engineers evaluate the feasibility of upgrading boiler control systems, and develop budgetary-cost proposals to upgrade controls for gas- or oil-fired boilers, or high-temperature hot water (HTHW) systems.

Approach

This study was conducted in four steps:

1. A literature review was conducted to gather information on the status of boilers and boiler control systems—both new and old technologies.

2. Basic control technology and related boiler control issues were investigated, including a review of available field instruments and their selection.

3. Current practices for developing budget proposals were reviewed, and a step-by-step approach was developed to guide the process. The proposal form was

presented in five parts, including plant description, unit benefits estimate, unit cost estimate, balance of plant cost estimate and summary.

4. Recommendations were made for monitoring subsequent engineering and contractor performance.

Scope

This is not a design guide; these general guidelines are meant to provide basic information to evaluate the feasibility of upgrading boiler control systems, and a methodology for developing budget proposals. Judgement must still be applied to develop designs to meet specific unit and site characteristics, boiler safety codes, and local regulatory requirements. These guidelines do not eliminate the need for competent professional engineers to finalize assessments of existing conditions, develop a plant control system design that meets existing and new requirements, and evaluate contractor proposals.

The emphasis of this work was to provide a controls application guide for gas- and oil-fired boilers. No provisions were made for coal or other solid fuel-fired units.

Mode of Technology Transfer

It is recommended that the information presented in this report be incorporated into an Army Design Guide (DG). It is also recommended that the system selection guidelines be incorporated into installation training programs for heating plant personnel, facility engineers, and utility supervisors since such guidelines would be of great value to U.S. Army Corps of Engineers Districts responsible for heating plant design and construction.

Disclaimer

Reference to commercial manufacturers or their products is made for information only, and is not meant as an endorsement of product or manufacturer. An alphabetical listing of included manufacturers follows:

Name	Location	Phone
Action Instruments	San Diego, CA 92123	619/279-5726
Allen-Bradley Co., Inc.	Cleveland, OH 44143	216/646-5000
Ashton-Tate (Borland International)	Scotts Valley, CA 95066	408/438-8400
Heuristics, Inc.	Sacramento, CA 95827	916/369-6606
Iconics, Inc.	Foxborough, MA 02035	518/543-8600
Intec Controls	Walpole, MA 02081	508/660-1221
Intellution, Inc.	Norwood, MA 02062	617/769-8878
LABTECH	Wilmington, MA 01887	508/657-5400

2 Boilers and Operating Performance

Central Heating Plants

The main purpose of the central heating plant is to satisfy the heating needs by generating and distributing steam in a safe, reliable and cost-effective manner (Wohadlo et al., 1990). The heart of the central heating plant is the boiler where steam or high temperature hot water (HTHW) is generated. Successful and efficient operation of the boiler requires several supporting processes to maintain boiler performance:

- Feed Water Treatment—Raw process water contains scale-forming ions of calcium and magnesium, commonly known as "hardness ions." Boiler feed water is produced by treating the raw water to protect the boiler against internal scale buildup and corrosion. Treatment includes a softening process (removal of hardness ions) and a deaeration process (removal of dissolved oxygen). Treated water quality requirements are monitored by conductivity and pH measurements. Selection of the appropriate water softening processes depends on the operating pressure of the boiler. Control functions include interlock, sequential (regeneration of resin beds), and regulatory operations. Automatic feedback loops consist of maintaining a deaerator level and pressure control.

- Condensate Return—Typical installations provide a condensate return system that recovers and collects spent steam (condensate) for reuse as boiler feedwater. Condensate recovery reduces water treatment and chemical injection costs.

- Interlock and regulatory control functions include condensate pump and recovery tank level instrumentation. Condensate pH and conductivity are sampled to monitor process contamination.

- Blowdown—During the steaming process, suspended solids accumulate in the boiler. Excessive amounts can affect boiler operation and economics. Blowdown removes these solids in accordance with acceptable limits. Total conductivity is normally used as an index for regulating the amount of water removed. Periodic on/off or continuous analog regulatory control methods can be used.

- Chemical Injection—Internal treatment of the boiler water by chemical injection is commonly used to help prevent boiler scaling. Appropriate treatment depends on the boiler operating conditions and water quality. Control functions may be either interlock or regulatory.

- Fuel Conditioning—This includes equipment and devices necessary to properly prepare and handle the gaseous and/or liquid fuels feeding the boiler's burner(s). Natural gas fuels normally require no more than pressure reduction. Fuel oil, on the other hand, needs a storage system, pumps, heating elements, atomizing agents, and control hardware.

- Steam Allocation—Central heating plants with multiple boilers typically use a load allocation scheme to distribute total demand to each boiler. Load allocation is based on performance data relating boiler efficiency to operating load.

- Emission Control—Control heating plants are often subject to environmental regulations set by Federal and/or State agencies. Adherence of these requirements might include the use of dust collection and wet gas scrubber equipment. Controls normally involve interlock, sequential, and regulatory functions to automate equipment operation.

- Boiler—The heart of a central heating plant is the boiler. Typical components in a boiler installation are shown in Figure 1. Briefly, a boiler consists of a furnace where fuel and air are mixed and burned. Several different fuels can be used. This study considered only gas and oil. Air required for combustion is forced into the furnace by a forced air draft fan. Some boilers operate with positive pressure. Larger boilers operate with a slight negative pressure that requires an induced draft fan to pull the gases through the boiler and out the stack. These hot combustion gases heat water-filled-tubes that are connected to a drum, to produce steam. A consistent drum level is maintained by adding feedwater to make up for steam produced. Control requirements include interlock (for safety), sequential (burner management) and regulatory (combustion control and feed water) controls.

Boilers

Boilers may produce either steam at various pressures or HTHW at various temperatures and pressures. Boilers are classified in three size ranges for purposes of these guidelines:

1. Small: A single boiler with a capacity of 3,000 to 15,000 pph,* typical of light commercial and mid-size institutions to service heating loads.

2. Medium: Multiple boilers with capacities of 10,000 to 60,000 pph to service heating/air conditioning and power generation.

3. Large: Multiple boilers with capacities of 60,000 to 300,000 pph to service heating/air conditioning, process load, and power generation.

A simple boiler consists of two separate systems. Water is introduced to the steam-water system (the water-side of the boiler) treated, and converted to steam. The fuel and air are mixed and burned in the furnace, providing the heat needed for steam generation. The fuel-air-flue gas system is also called the fire-side of the boiler. Separate heat exchangers such as an air preheater and economizer can be used to recover the heat contained in the flue gases and to improve the thermal efficiency of the boilers.

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* pph = lb/hour; 1 lb = 0.453 kg.

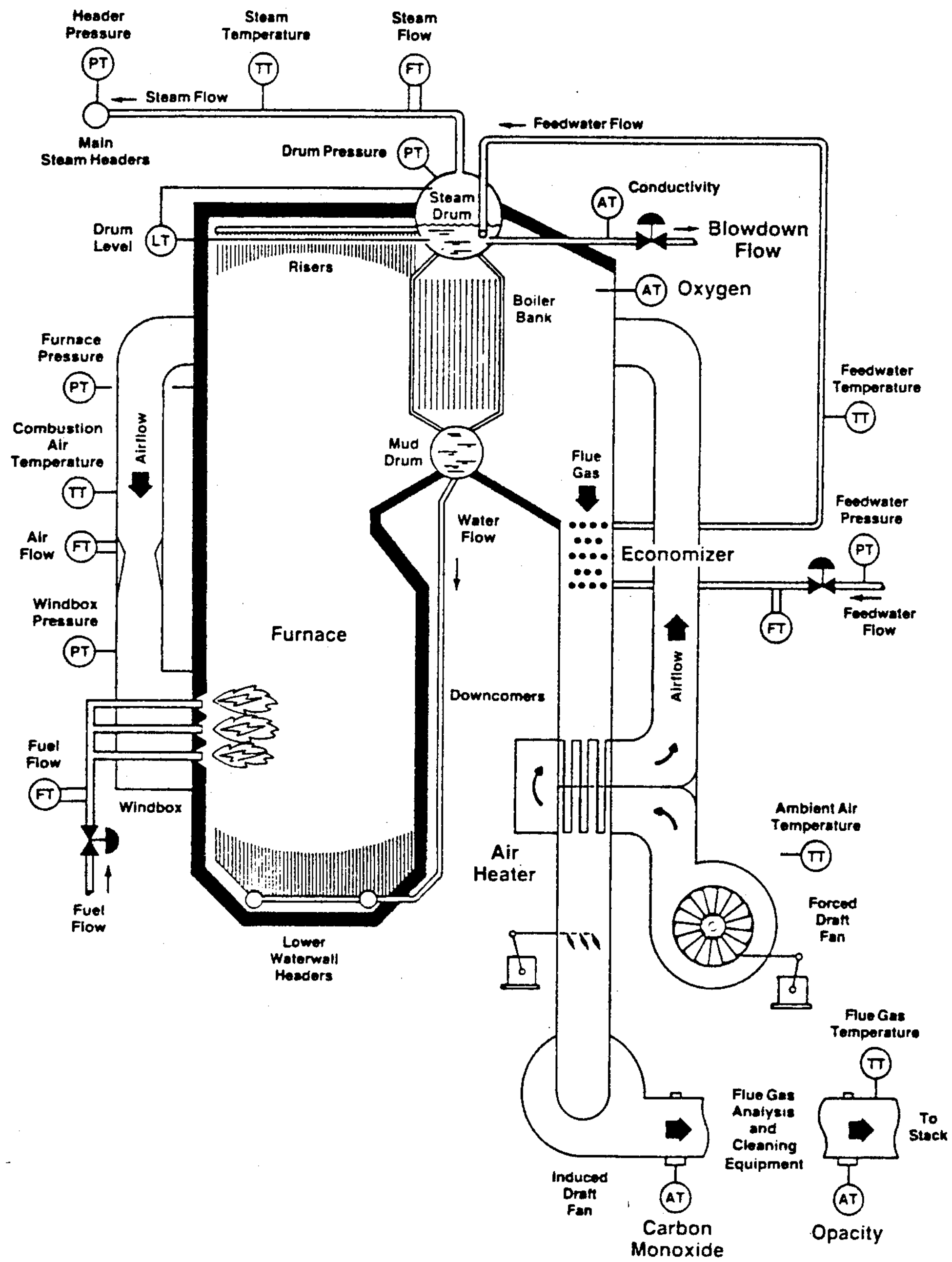


Figure 1. Typical boiler components.

Boiler designs may use either firetubes or watertubes. In firetube boilers, the combustion gas products flow through boiler tubes surrounded by water. Combustion usually takes place in a furnace under the boiler vessel, and the hot flue gases traverse the tubes in a number of passes before being discharged to the stack. The firetube boilers are limited to smaller sizes and lower steam pressures, because the pressure of the steam must be contained by the shell of the boiler vessel. Most firetube boilers are shop-assembled packaged units, fired by gas and/or oil, as well as coal. Figure 2 shows a cross-sectional view of a two-pass firetube boiler.

In watertube boilers, steam is generated by passing water through the boiler tubes, with combustion and gas flow taking place outside of the tubes. The tubes are usually connected between two cylindrical drums to provide natural circulation of the water within the unit. Hot water and steam rise to the higher drum (the steam drum), where steam separates from the water. Sludge that may develop in the boiler flows down to the lower drum (the mud drum), and is removed from the system by periodic blowdown. Forced circulation, once-through watertube boilers are typically used to generate high pressure steam in a very short time. Water tube boilers are suited to larger sizes and higher pressures. Figure 3 shows a cross-sectional view of a watertube boiler.

Boiler design involves the interaction of many variables such as water-steam circulation, heat transfer, firing system and heat input, and fuel characteristics. The water-steam circulation absorbs heat from the tube metal at a rate that assures sufficient cooling of the furnace-wall tubes, during operating conditions, with an adequate margin of reserve for transient upsets. Adequate circulation prevents excessive metal temperatures or temperature differentials that would cause failures due to overstressing, overheating, or corrosion.

Several available reference documents describe different types of boilers in detail and provide insights for operation and maintenance. References for gas/oil and coal fired units are listed at the end of this report. Appendix A gives selected references to manuals of value to particular situations.

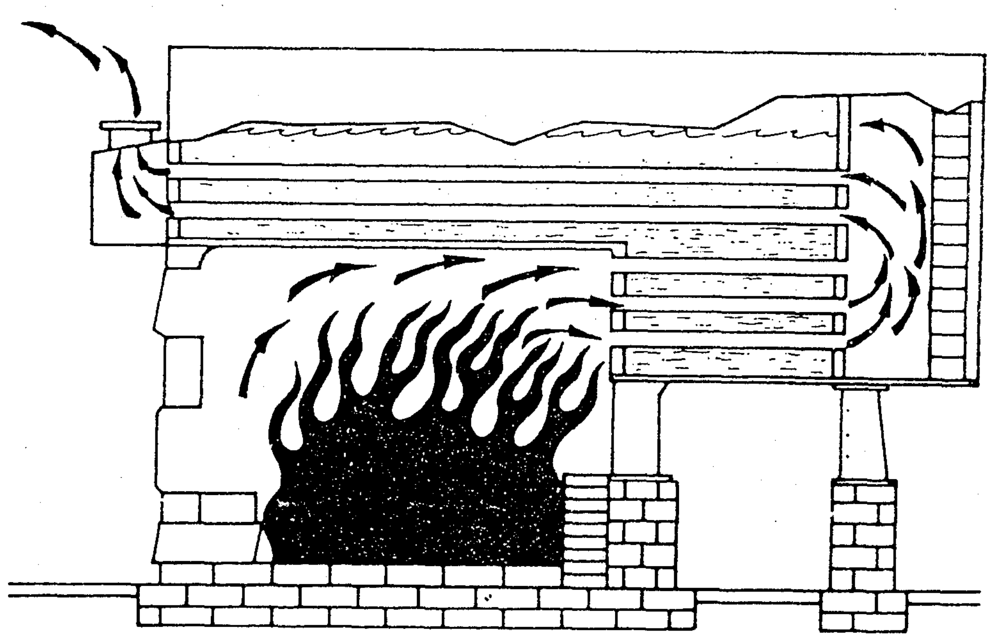


Figure 2. Two-pass fire tube boiler.

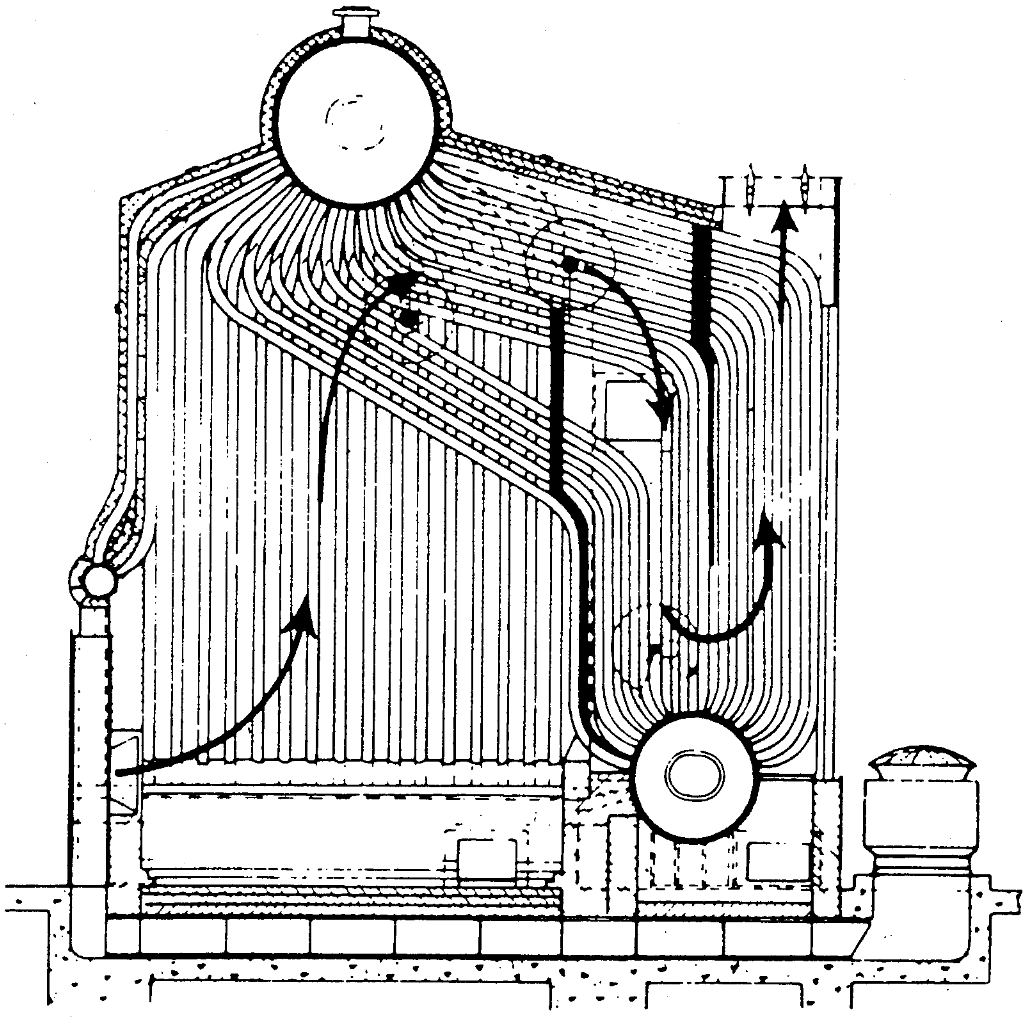


Figure 3. Water tube boiler.

Mechanical Fitness

The mechanical fitness of any heating plant is a result of quality of design, quality of equipment, proper installation, attentive operation, adherence to preventative maintenance programs, and maintaining a highly trained staff. Modern control systems can improve the performance of a mechanically fit boiler. However, even the best control system cannot compensate for a mechanically unfit boiler. A procedure has been developed to evaluate the cost to restore mechanical fitness (Stanley Consultants 1991).

Operating Economics

Efficiency, cost, reliability and service/support are the main criteria for selecting a boiler control system. In terms of efficiency, there are two major considerations:

1. At a given firing rate, how closely can the system control excess O_2 or air.
2. As the firing rate varies, how much deviation is allowed between the actual and the desired value of O_2.

Table 1 summarizes the capability of various control systems to control excess O_2 at a given firing rate. The minimum possible excess occurs with about 200 ppm of CO in the exhaust. Any further lowering of excess air yields unacceptable levels of incomplete combustion. Table 2 lists practical excess O_2 limits, and Table 3 lists potential annual savings for various unit sizes at different fuel costs.

Existing boiler efficiencies can be determined using the ASME Abbreviated Efficiency Test. Forms are provided in Figures 4 and 5. Figures 6, 7, and 8 show approximate boiler efficiencies at various stack temperatures for boilers firing natural gas, #2 fuel oil, and #6 fuel oil, respectively.

A less rigorous approach can be used by plant personnel to develop initial proposals for control systems upgrades. Savings can be estimated for a given load, by measuring the current percentage excess O_2 versus the minimum percentage excess O_2 that can be expected from an upgraded control system. Appendix B includes guidelines for selecting combustion controls for systems with small, medium, or large boilers. Appendix C, Part 2 contains a form for determining potential energy savings, and Appendix D shows completed sample forms. Operating hours are listed for each of four operating load ranges. Operating costs are calculated for each load range, based on average fuel cost and unit capacity. Potential savings are estimated by comparing actual and target excess oxygen (O_2).

Table 1. Performance of boiler control systems.

Type of Fuel	Control System*	Tolerance on Steam Pressure (% of Setpoint)**	Tolerance on Exhaust (% O_2)***
Oil	On/Off	± 6	± 0.5
	High/Low/Off	± 5	± 0.5
	Modulating Positioning	± 3	± 0.5
	Semimetering	±3	± 0.4
	Full-Metering	±3	± 0.3
Gas	On/Off	± 6	± 0.4
	High/Low/Off	± 5	± 0.4
	Modulating Positioning	± 3	± 0.4
	Semimetering	±3	± 0.3
	Full-Metering	±3	± 0.2

* Source: *Combustion Equipment and Related Facilities for Non-Residential Heating Boilers,* Technical Report 51 (Federal Construction Council) reprinted in *U.S. Air Central Heating Plant Tuneup Workshop, Volume VIII: Combustion Control—Oil/Gas,* January 1990.

** Data are given for loads greater than 33 percent of rated value. Below 33 percent load, the tolerance will approximately double.

*** O_2 compensation typically reduces tolerance by 1/3 to 1/2 of the value without O_2 compensation.

Table 2. Minimum percentage O_2 in flue gas.

Type of Fuel	Minimum % O_2
Natural Gas	1.5
#2 Oil	2.0
#6 Oil	2.5
Source: *U.S. Air Force Central Heating Plant Tuneup Workshop, Volume VIII: Combustion Control—Oil/Gas* (January 1990).	

Table 3. Annual dollars saved for 5 percent improvement in boiler efficiency.

	Fuel Price				
Steam Production	**\$3.00* or 45¢/gal**	**\$4.00* or 60¢/gal**	**\$5.00* or 75¢/gal**	**\$6.00 or 90¢/gal**	**\$8.00 or \$1.20/gal**
100 hp or 3,450 lbm/hr	\$6,900	\$9,200	\$11,500	\$13,800	\$18,400
200 hp or 6,900 lbm/hr	\$13,800	\$18,400	\$23,000	\$27,600	\$36,800
400 hp or 13,800 lbm/hr	\$27,600	\$36,800	\$46,000	\$55,200	\$73,600
800 hp or 27,600 lbm/hr	\$55,200	\$73,600	\$92,000	\$110,400	\$147,200
40,000 lbm/hr	\$80,000	\$106,667	\$133,333	\$160,000	\$213,334
60,000 lbm/hr	\$120,000	\$160,000	\$200,000	\$240,000	\$320,000
80,000 lbm/hr	\$160,000	\$213,334	\$266,667	\$320,000	\$426,668
100,000 lbm/hr	\$200,000	\$266,666	\$333,333	\$400,000	\$533,332
200,000 lbm/hr	\$400,000	\$533,333	\$666,667	\$800,000	\$1,466,666
300,000 lbm/hr	\$600,000	\$800,000	\$1,000,000	\$1,200,000	\$1,600,000
400,000 lbm/hr	\$800,000	\$1,066,666	\$1,333,333	\$1,600,000	\$2,133,332
500,000 lbm/hr	\$1,000,000	\$1,333,334	\$1,666,667	\$2,000,000	\$2,666,668
1,000,000 lbm/hr	\$2,000,000	\$2,666,667	\$3,333,333	\$4,000,000	\$5,333,334
*Price in \$/million Btu or \$/thousand cu ft of gas (Dyer & Maples 1980).					

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

SUMMARY SHEET PTC 4.1-a(1964)

	TEST NO.	BOILER NO.	DATE
OWNER OF PLANT	LOCATION		
TEST CONDUCTED BY	OBJECTIVE OF TEST		DURATION
BOILER, MAKE & TYPE		RATED CAPACITY	
STOKER, TYPE & SIZE			
PULVERIZER, TYPE & SIZE		BURNER, TYPE & SIZE	
FUEL USED MINE	COUNTY	STATE	SIZE AS FIRED

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psia	
2	STEAM PRESSURE AT S. H. OUTLET	psia	
3	STEAM PRESSURE AT R. H. INLET	psia	
4	STEAM PRESSURE AT R. H. OUTLET	psia	
5	STEAM TEMPERATURE AT S. H. OUTLET	F	
6	STEAM TEMPERATURE AT R.H. INLET	F	
7	STEAM TEMPERATURE AT R.H. OUTLET	F	
8	WATER TEMP. ENTERING (ECON.)(BOILER)	F	
9	STEAM QUALITY % MOISTURE OR P. P. M.		
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	
11	TEMP. AIR FOR COMBUSTION (This is Reference Temperature) †	F	
12	TEMPERATURE OF FUEL	F	
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM.	Btu/lb	
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb	
18	ENTHALPY OF REHEATED STEAM R.H. INLET	Btu/lb	
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb	
20	HEAT ABS/LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	
21	HEAT ABS/LB R.H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	

HOURLY QUANTITIES

26	ACTUAL WATER EVAPORATED	lb/hr	
27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	
29	TOTAL HEAT INPUT $\frac{\text{(Item 28} \times \text{Item 41)}}{1000}$	kB/hr	
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	
31	TOTAL HEAT OUTPUT $\frac{\text{(Item 26}\times\text{Item 20)+(Item 27}\times\text{Item 21)+Item 30}}{1000}$	kB/hr	

FLUE GAS ANAL. (BOILER)(ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	
33	O_2	% VOL	
34	CO	% VOL	
35	N_2 (BY DIFFERENCE)	% VOL	
36	EXCESS AIR	%	

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt		OIL	
37	MOISTURE		51	FLASH POINT F*	
38	VOL MATTER		52	Sp. Gravity Deg. API*	
39	FIXED CARBON		53	VISCOSITY AT SSU* BURNER SSF	
40	ASH		44	TOTAL HYDROGEN % wt	
	TOTAL		41	Btu per lb	
41	Btu per lb AS FIRED				
42	ASH SOFT TEMP.* ASTM METHOD			GAS	% VOL

	COAL OR OIL AS FIRED ULTIMATE ANALYSIS				
43	CARBON		54	CO	
44	HYDROGEN		55	CH_4 METHANE	
45	OXYGEN		56	C_2H_2 ACETYLENE	
46	NITROGEN		57	C_2H_4 ETHYLENE	
47	SULPHUR		58	C_2H_6 ETHANE	
40	ASH		59	H_2S	
37	MOISTURE		60	CO_2	
	TOTAL		61	H_2 HYDROGEN	
				TOTAL	

	COAL PULVERIZATION				
				TOTAL HYDROGEN % wt	
48	GRINDABILITY INDEX*		62	DENSITY 68 F ATM. PRESS.	
49	FINENESS % THRU 50 M*		63	Btu PER CU FT	
50	FINENESS % THRU 200 M*		41	Btu PER LB	
64	INPUT-OUTPUT EFFICIENCY OF UNIT %	$\frac{\text{ITEM 31} \times 100}{\text{ITEM 29}}$			

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS		
66	HEAT LOSS DUE TO MOISTURE IN FUEL		
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2		
68	HEAT LOSS DUE TO COMBUST. IN REFUSE		
69	HEAT LOSS DUE TO RADIATION		
70	UNMEASURED LOSSES		
71	TOTAL		
72	EFFICIENCY = (100 – Item 71)		

Figure 4. Summary sheet, ASME test form for abbreviated efficiency test.

CALCULATION SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

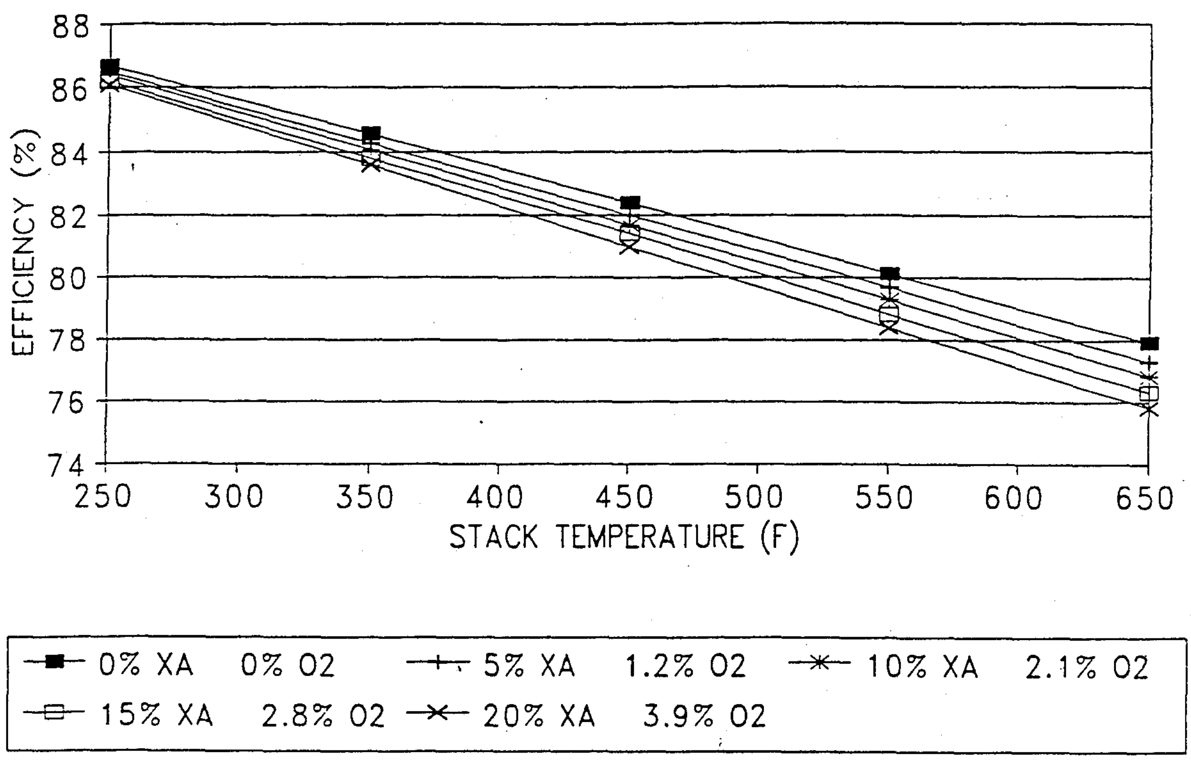
PTC 4.1-b (1964)

OWNER OF PLANT TEST NO. BOILER NO. DATE

30	HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR x $\left[\frac{\text{ITEM 15} - \text{ITEM 17}}{1000}\right]$ = ... kB/hr
24	*If impractical to weigh refuse, this item can be estimated as follows* DRY REFUSE PER LB OF AS FIRED FUEL = $\frac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$ CARBON BURNED PER LB AS FIRED FUEL = $\frac{\text{ITEM 43}}{100} - \left[\frac{\text{ITEM 22} \times \text{ITEM 23}}{14{,}500}\right]$ = ... NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.
25	DRY GAS PER LB AS FIRED FUEL BURNED = $\frac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)} \times$ (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S) $= \frac{11 \times \text{ITEM 32} + 8 \times \text{ITEM 33} + 7(\text{ITEM 35} + \text{ITEM 34})}{3 \times (\text{ITEM 32} + \text{ITEM 34})} \times \left[\text{ITEM 24} + \frac{\text{ITEM 47}}{2.67}\right]$ = ...
36	EXCESS AIR† $= 100 \times \frac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})} = 100 \times \frac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682\,(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})}$ = ...

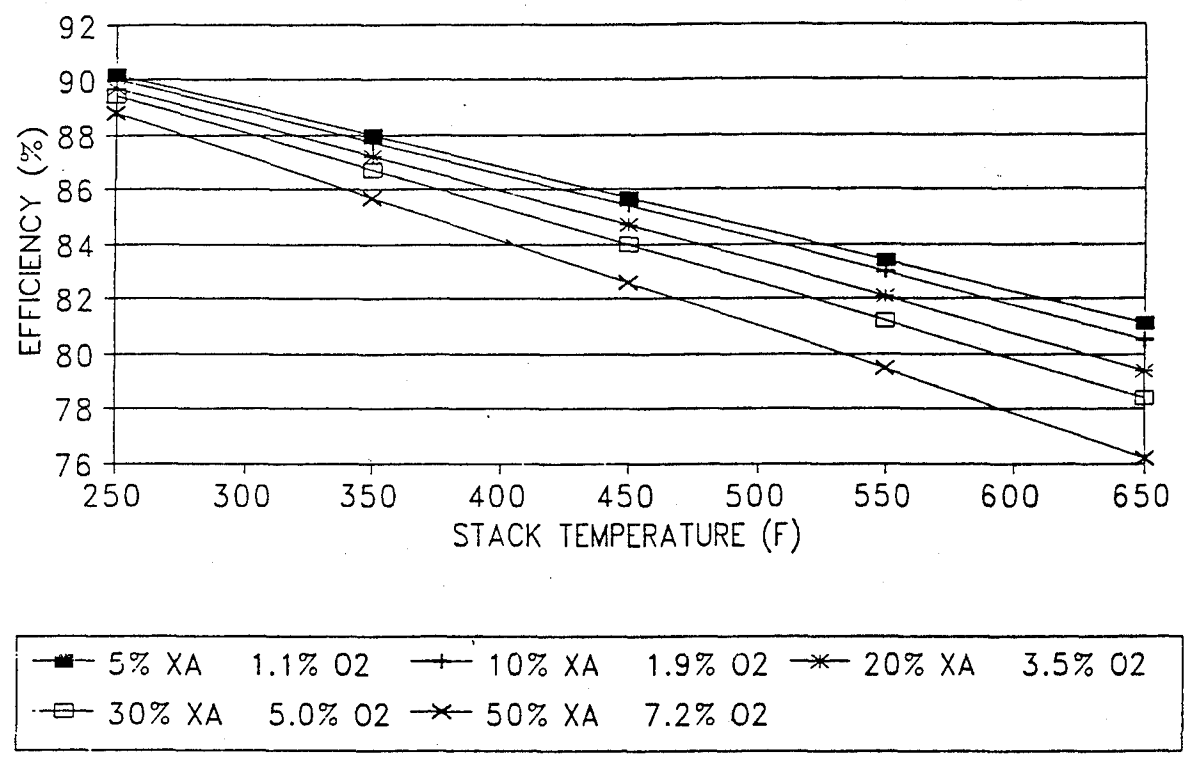
	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	$\frac{\text{LOSS}}{\text{HHV}} \times 100 =$	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL $\times C_p \times (t_{lvg} - t_{air})$ = $\frac{\text{ITEM 25}}{\text{Unit}} \times 0.24$ (ITEM 13) – (ITEM 11) = ...	......	$\frac{65}{41} \times 100 =$	......
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL x [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) – (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\text{ITEM 37}}{100}$ x [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) – (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{66}{41} \times 100 =$	......
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ x [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) – (ENTHALPY OF LIQUID AT T AIR)] = 9 x $\frac{\text{ITEM 44}}{100}$ x [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) – (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{67}{41} \times 100 =$	......
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 x ITEM 23 = ...	......	$\frac{68}{41} \times 100 =$	......
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$	......	$\frac{69}{41} \times 100 =$	......
70	UNMEASURED LOSSES **	......	$\frac{70}{41} \times 100 =$	......
71	TOTAL	......	......	......
72	EFFICIENCY = (100 – ITEM 71)	......	......	......

Figure 5. Calculation sheet, ASME test form for abbreviated efficiency test.



XA = Excess Air
O_2 = Oxygen Content, Wet Basis
Approximate Boiler Efficiency =
Efficiency due to Stack Loss Minus Radiation Loss Minus Blowdown Loss

Figure 6. Stack temperature vs. efficiency—natural gas.



XA = Excess Air
O_2 = Oxygen Content, Wet Basis
Approximate Boiler Efficiency =
Efficiency due to Stack Loss Minus Radiation Loss Minus Blowdown Loss

Figure 7. Stack temperature vs. efficiency—#2 fuel oil.

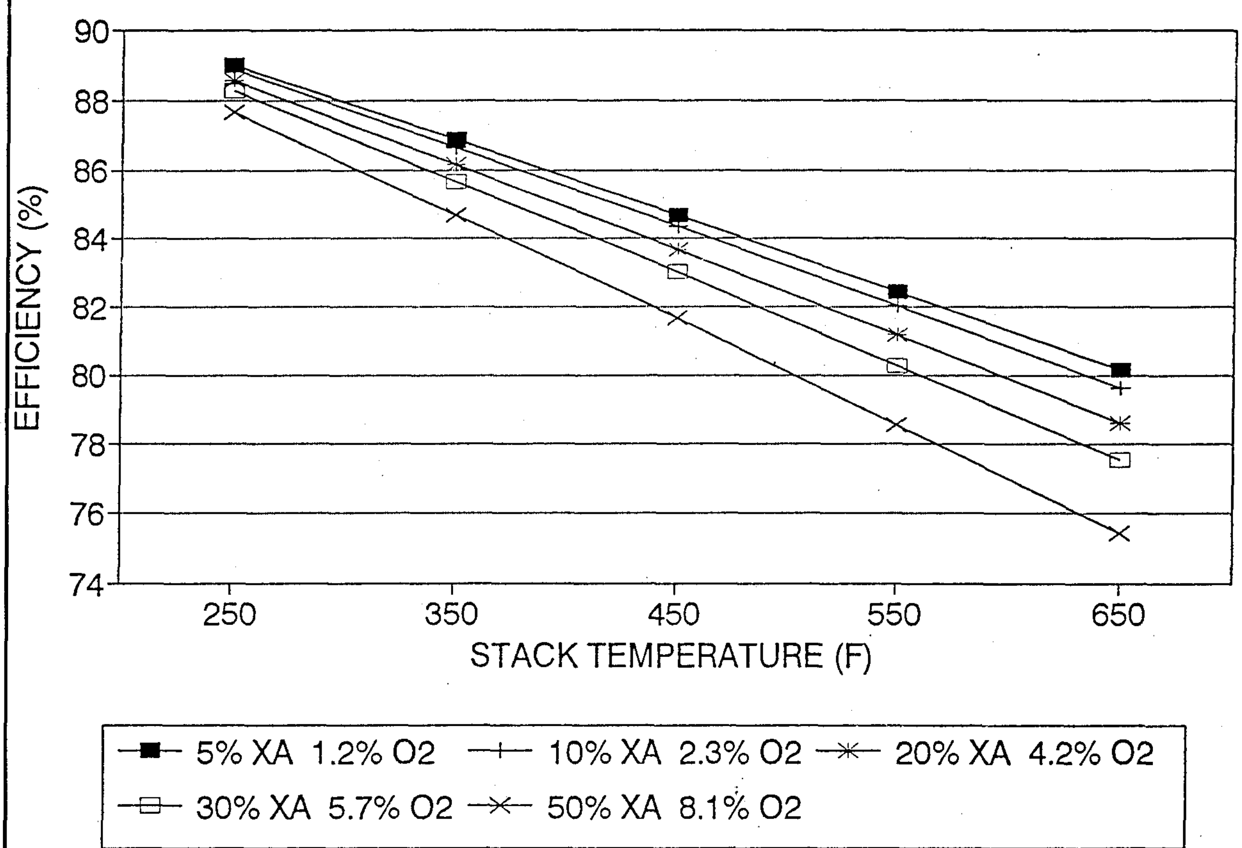


Figure 8. Stack temperature vs. Efficiency—#6 fuel oil.

3 Introduction to Boiler Controls

Description of Boiler Control Systems

Boiler controls support regulatory, sequential and interlock activities. The regulatory and sequential requirements for boiler installations are usually governed by operating philosophies, process load requirements, safety codes and insurance guidelines (Wohadlo et al. 1990; Maples et al. 1990). Interlock requirements are set forth by the National Fire Code (NFPA-85). Factory Mutual (FM), Industrial Risk Insurers (IRI), and Underwriters Laboratory (UL) also publish applicable guidelines.

Regulatory loops on boilers execute direct control over feedwater and the combustion processes. These continuous functions determine the boiler's performance. Different regulatory loops associated with boiler control may include the steam header pressure, steam drum level, steam temperature, fuel/air ratio, excess air (or oxygen) trim, and furnace pressure.

Effective fuel/air ratio control is the major factor that control systems can address to improve boiler efficiency. Many control technologies of varying sophistication apply to fuel/air ratio control. The information presented in this chapter can help provide the understanding needed to use existing controls more effectively and to make proper decisions when purchasing new or modified controls.

Basic Terminology

Boiler combustion controls considered here have two main functions: to maintain constant steam pressure (or temperature in the case of High Temperature Hot Water Systems) and to maintain the proper combustion air/fuel ratio for efficient operation. Various types of combustion controls share the common elements described below.

- *Measuring Device*: Any device used to indicate the magnitude of a physical property by an output signal (either electrical or mechanical). For example, the device could be a pressure transducer with a millivolt output proportional to the measured pressure.

- *Setpoint*: A reference signal (either mechanical or electrical) that represents the desired value of the measured variable.

- *Feedback*: A signal, proportional to the magnitude of the controlled variable, produced by the measuring device. Feedback is combined with a "setpoint" signal to produce a signal indicating the required amount of control. This combined signal is the input to the automatic controller.

- *Automatic Controller*: A device that receives the process measurement signal and produces an output signal that reduces the deviation between the measured quantity and corresponding setpoint.

- *Output Signal*: An actuating signal from an automatic controller that causes the controlling element to modify the process condition (i.e., close off a valve or open a damper slightly).

- *Control Element*: An apparatus, usually a valve or damper, that establishes a flow rate according to the output signal.

- *Control Element Position Indicator*: A device that provides a means for determining the position of the control element.

More complex control systems may contain other devices; however, the elements discussed above are the most important and provide an adequate basis for understanding a boiler control system.

Control systems in general can be classified as either "open-loop" or "closed-loop." Open-loop controls use a calibration curve that relates the fuel valve setting to steam demand to set the firing rate. While open-loop systems are simple, they result in poor control due to changes in the calibration caused by wear, fouling, and other problems. Loop performance can be improved by adding a process feedback signal such as steam flow. The feedback or closed-loop control adjusts for changes in fuel quality, instrument calibration, and other conditions. Therefore, closed-loop control is preferred for boiler control.

PID Controllers

Figure 9 shows the basic functions of a closed loop controller. Beginning with the controller, the various functions are explained as follows. The controller receives two types of signals: (1) setpoint values for desired steam pressure, flow, temperature, fuel

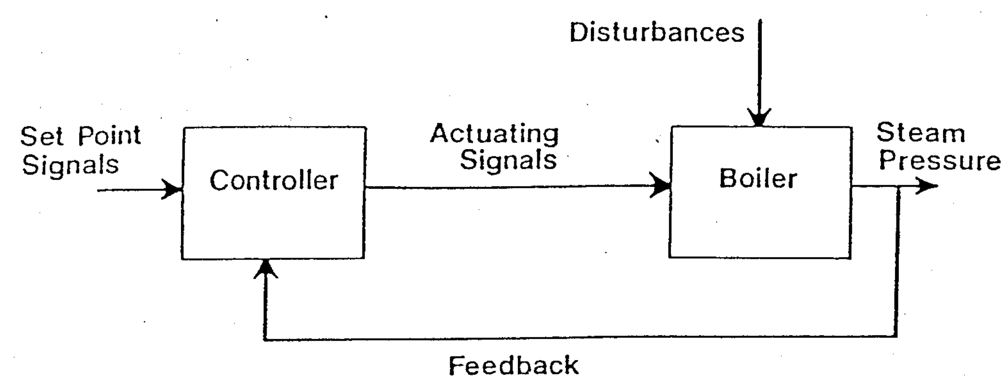


Figure 9. Boiler control functions.

flow, air flow, etc., and (2) feedback indicating the actual process conditions. The function of the controller is to compare the process variable against setpoint to produce a compensating output signal. If all conditions are perfect, the output signals result in the correct air/fuel ratio and firing rate. However, many "disturbances" result in the need for feedback, such as fuel property changes, air properly changes, fouled or worn burners, and linkage hysteresis.

Each controller output signal is obtained by comparing the setpoint and feedback signals with the desired activation. Three basic control actions are used to process these signals and provide the desired output.

The proportional action adjusts the magnitude of the output in proportion to the difference between the setpoint and feedback signals (called the "error signal"). Figure 10 shows an example of this type of control. The error signal is magnified (or diminished) by an appropriate constant *K*, which is used to produce the output to the fuel valve. A large value of *K* tends to drive the error signal to zero more quickly, but at greater risk of dynamic instability. Figure 11 shows the response of a boiler control system with different values of proportional gain. Notice in Figure 11 that a proportional controller does not drive the error signal to zero as shown by the difference between the setpoint and output pressure (called "offset"). Notice also that the offset reduces as the gain, *K* increases.

Integral action eliminates the offset in the proportional control by working to reduce error to zero, over time. In this type of control, the output is proportional to the combination of the error signal and the integral of the error signal over a certain time

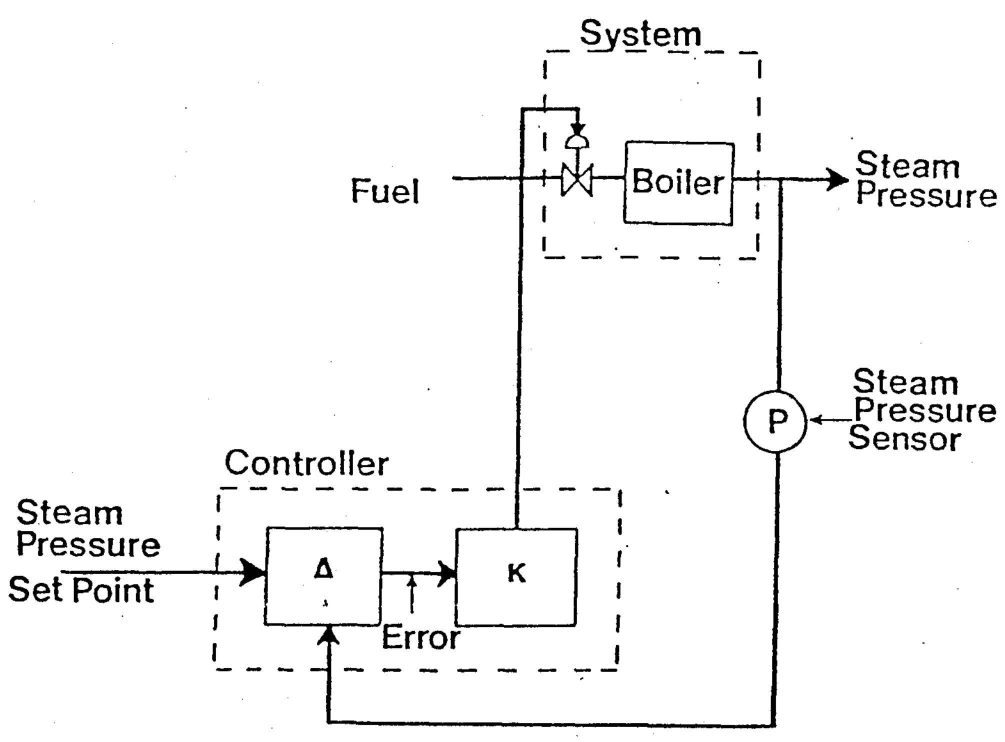


Figure 10. Typical modulating positioning system.

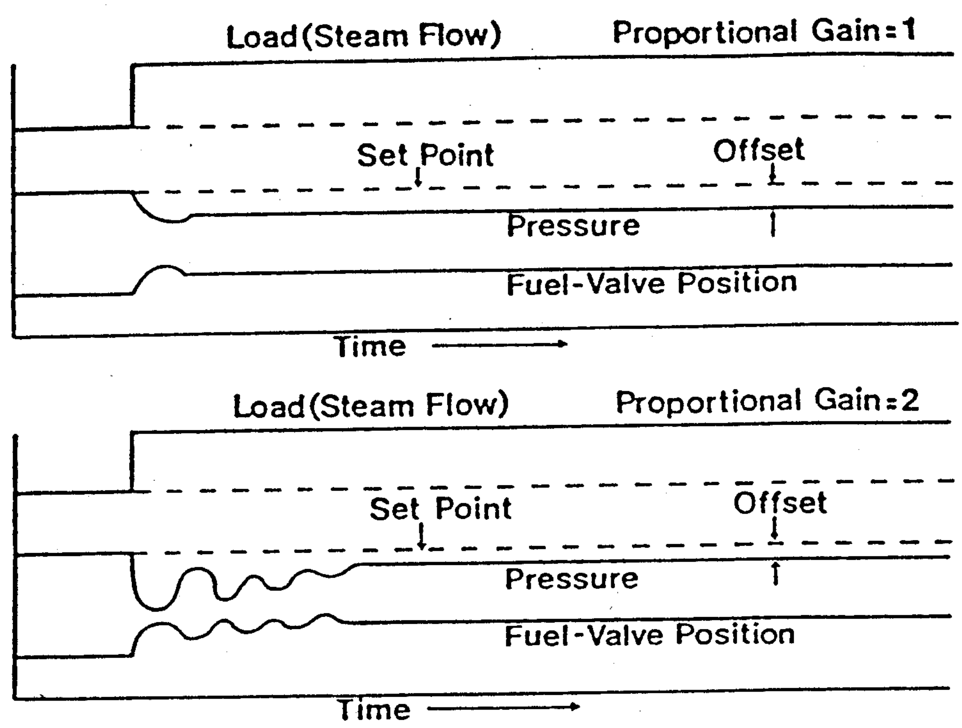


Figure 11. Response of proportional controller with different gain values.

period. Figure 12 shows a typical response for a proportional integral controller. This figure shows how the system operates without an offset in a steady mode. However, notice the increased instability in pressure and fuel valve opening.

Derivative action adds a third mode—the rate of change of the error signal with time. The activation caused by this controller is proportional to a weighted sum of the error signal (its integral value over the disturbance time period) and its instantaneous rate of change. Figure 13 shows a typical response of this system.

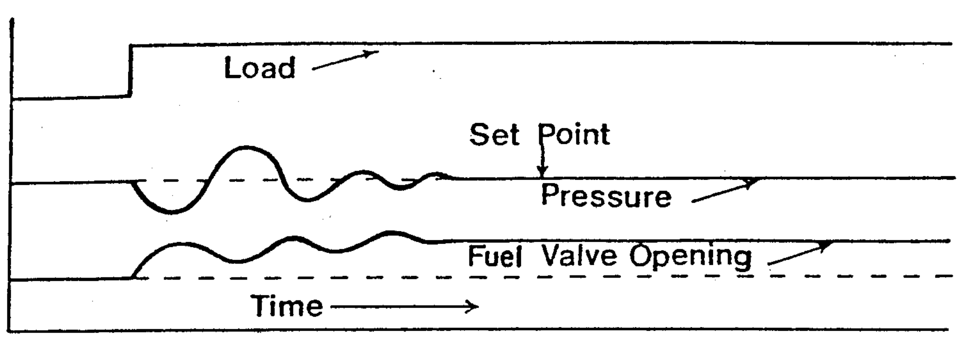


Figure 12. Typical response of proportional plus integral control.

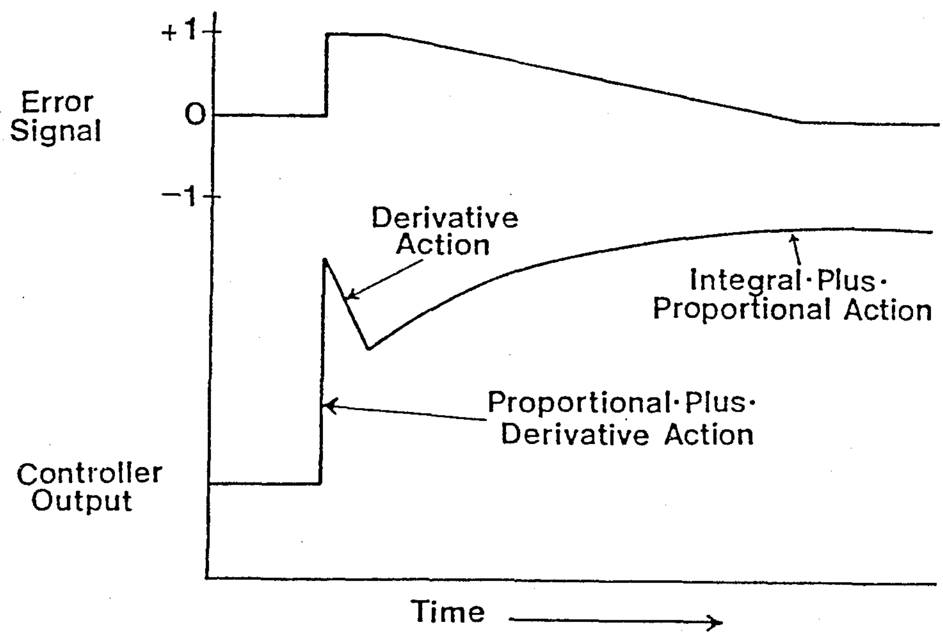


Figure 13. Typical response of proportional, integral, derivative controller.

Combustion Control

The steam pressure and setpoint signal are fed to the master regulator. The master regulator has a single output (usually a mechanical jackshaft in smaller units, as shown in Figure 14) which activates the fuel valve (or valves in the case of dual fuel capability) and the fan air louvers. The output of the master regulator is usually of the proportional type described above. In Figure 14, the fuel valve setting is characterized by adjusting the cam curvature over which the fuel pin travels. Many systems do not have this capacity. In the case of on/off and high/low/off systems, the characterization is generally not needed. However, for modulating controllers, fuel characterization and/or CO or O_2 trim are essential to low-excess air operation. The following conditions, in addition to fuel characterization, are required to implement positioning control:

- Maintain fuel pressure between narrow limits.
- Maintain the heating value of the fuel and other fuel properties such as viscosity of oil nearly constant.
- Eliminate hysteresis in linkages. The controls shown in Figures 14 and 15 are both of the Parallel type. However, both positioning and metering controls can occur in Series, Parallel or Series/Parallel form, as described below.

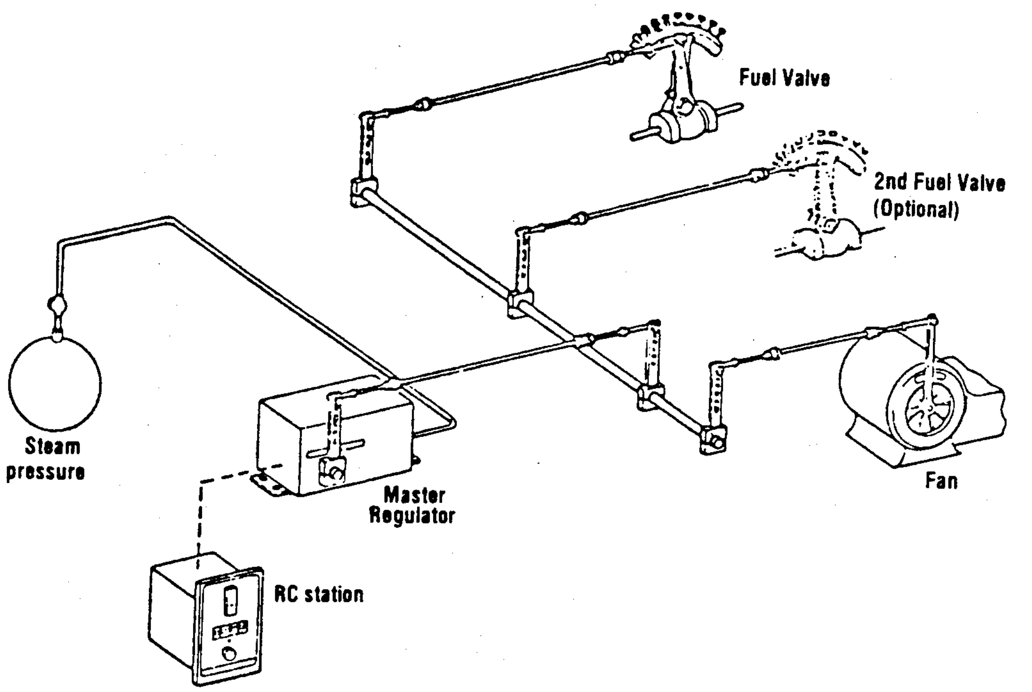


Figure 14. Jackshaft positioning control.

- Series: The deviation in steam pressure is used to set one variable (fuel or air). The other variable is set based on this controlled variable. Air is used as the controlled variable on boilers required to increase load rapidly and to shed load slowly. Fuel should be used as the controlled variable in the opposite situation. Series controls work well only where fuel properties, etc., are relatively constant; since this is a rare occurrence, series controls are seldom used.

- Parallel Positioning: The deviation in steam pressure causes the fuel and air flow to be set simultaneously. This is the most commonly used system.

- Series/Parallel (or Parallel Metered): In this system, fuel and air flow are set simultaneously (hence the "parallel" nature of the control). However, steam pressure and another control parameter such as steam flow are used to control fuel and air flow, respectively (hence the "series" nature of the control). Series/parallel control can usually give the tightest control on air/fuel ratio (Figure 16).

Selection of an appropriate combustion control strategy depends on unit size, operating characteristics, and operating schedule (i.e., winter only). On/Off or Hi/Lo/Off controls are found only on very small packaged units serving loads that can tolerate pressure or temperature fluctuations. Parallel (and jack shaft) controls are found on small- to medium-sized units, serving relatively stable loads with fuels that have stable btu content. Series/Parallel controls are used on larger units, on units with undersized

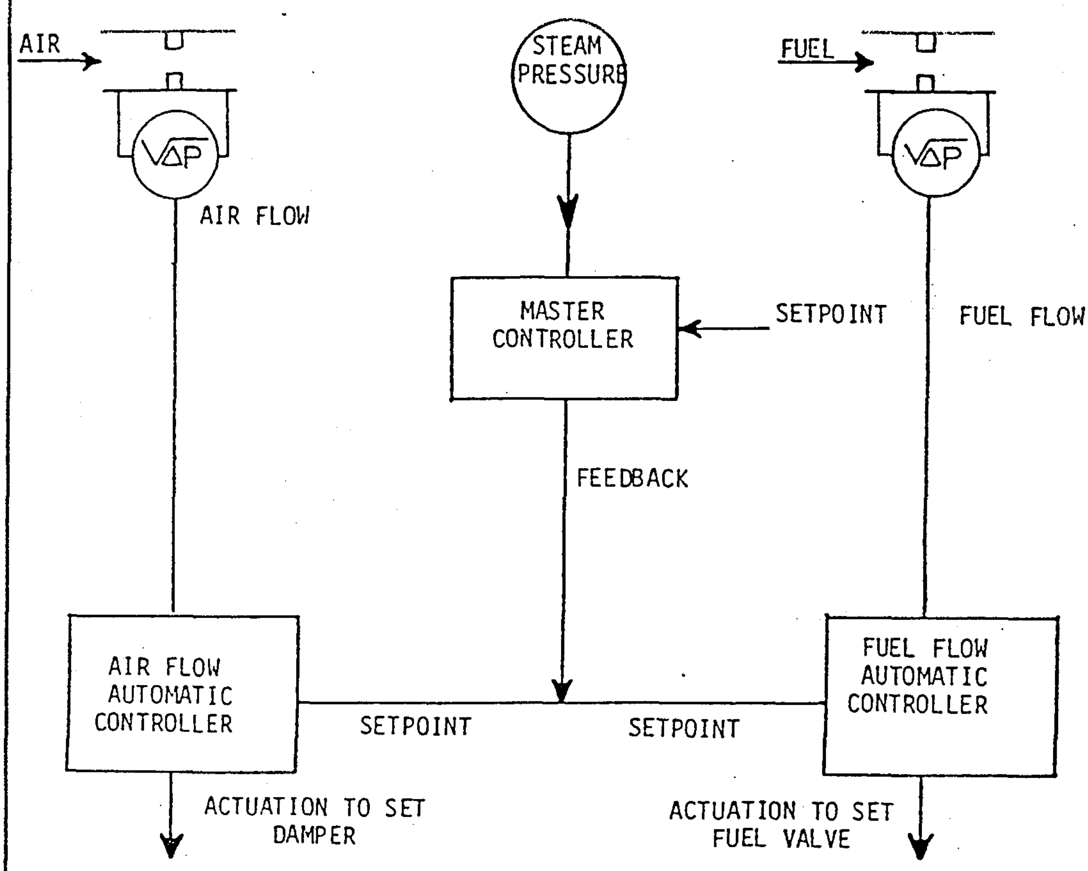


Figure 15. Parallel metering system.

drums, on units subject to wide demand fluctuations, or on those where fuel btu content can fluctuate. Units operating at low load offer less opportunity for controls upgrade, based solely on payback economics, since less stringent excess O_2 targets are feasible in these operating ranges. Units operating in partial seasons are subject to the same selection criteria as discussed above, but offer less opportunity for controls upgrade, based solely on payback economics.

Fuel-Air Trim

The controls discussed above are the closed-loop, feedback type, in which the steam pressure/flow rate is used as the control signal. An additional feedback loop can be installed to greatly improve efficiency in some cases. This additional feedback is the level of excess air (directly as O_2 in exhaust or indirectly as CO in exhaust). The function of this secondary feedback loop is to adjust the level of air supplied to the boiler based on the measured O_2 or CO level in the exhaust. The intent of this trim

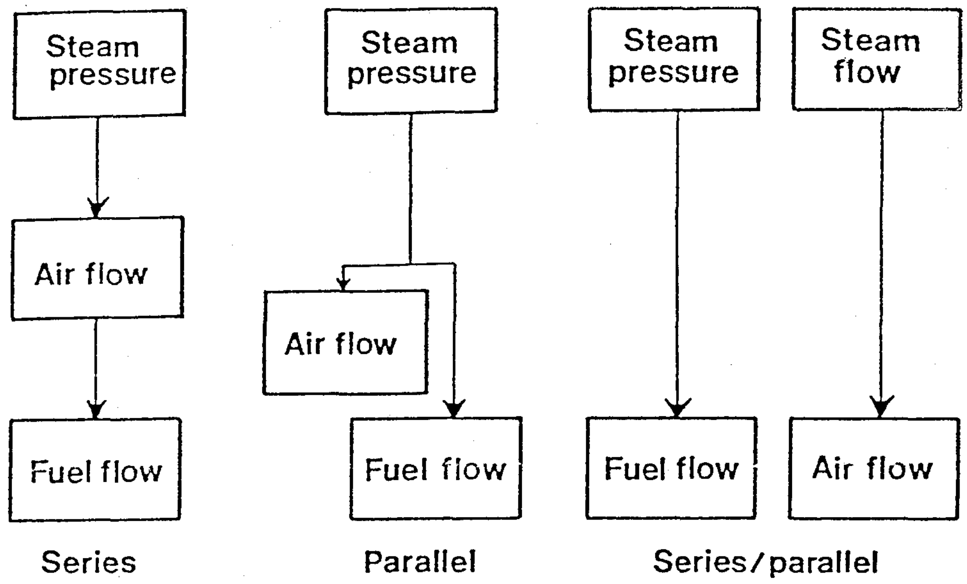


Figure 16. Types of controls.

is to provide a preset value (as a function of load) of O_2 and CO in the exhaust. Figure 17 shows O_2 trim applied to a basic parallel positioning system.

When an O_2 trim system is used, O_2 in a sample of flue gas is generally measured with a zirconium oxide sensor (either in the stack or furnace exit). Some automatic O_2 controllers have automatic calibration. It is very important to calibrate O_2 systems since all systems are subject to considerable drift. O_2 trim systems may not be justified on small units that constantly run at a near-full load. Periodic tests with portable equipment may produce similar benefits as an installed system, without the equipment and installation costs.

Reduction of excess air and associated heat losses results from maintaining proper combustion efficiencies. Measurement of the combustion products in the flue and their role in combustion control strategies are:

- Oxygen—Serves as a good index for excess air measurements, but not as an index of the quality of combustion. In conjunction with a well maintained and responsive combustion control system, an oxygen control loop will result in an approximate 2 to 4 percent savings of the boiler's fuel bill.

- Carbon Monoxide—A good index for the quality of combustion, but not an index of excess air measurement. As such, it should not be used as a prime controller for excess air trim.

- Oxygen + Carbon Monoxide—A good index for the quality of combustion, and a good index for excess air measurement. The oxygen trim performs the basic fuel/air ratio correction while the carbon monoxide trim portion provides a fine adjustment to the oxygen trim control to correct for the quality of combustion.

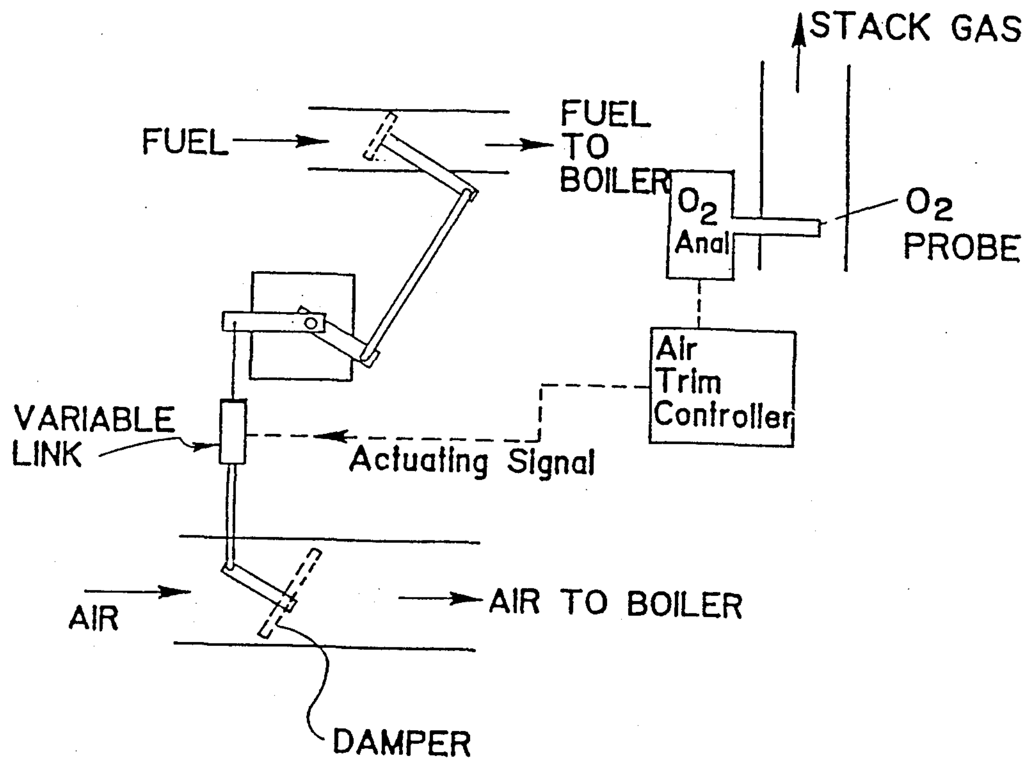


Figure 17. Oxygen trim system schematic.

When combined, the two provide the best technical approach to keep operation in the zone of maximum combustion efficiency.

Excess air trim control packages using an oxygen-based sensor are very common and adaptable to almost any size boiler. Carbon monoxide sensing is normally considered only for larger installations, because of its added cost. Conventional detectors are the in-situ type based on infrared or catalytic techniques. Oxygen measurement in the flue gas is normally measured with an in-situ zirconium oxide probe installed near the boiler flue gas outlet, thus minimizing tramp air effects.

Related Boiler Control Issues

In addition to combustion controls, several related control system issues affect availability and performance:

- flame management and safety
- air pollution control systems and emission monitoring
- information management

- operator interface
- fault tolerance.*

Flame Management and Safety

The boiler is a pressure vessel that is subjected to high temperatures and potentially hazardous combustion conditions. Safety is paramount. NFPA has published recommended minimum requirements for automatic safety interlocks. If a boiler is more than 5 years old, these need to be reviewed. It is important to shut down the boiler (cut off the fuel to the boiler) if the flame or air draft (forced or induced) is lost, or if the level of the water in the boiler drum is low, or the fuel supply is lost. It is also important to follow the start-up sequence, which normally requires purging of the boiler, pilot ignition, and burner fuel light-off. The control packages must meet all of these requirements.

Air Pollution Control Systems and Emission Monitoring

Evaluation of existing emission monitoring equipment may not be necessary because most plants will not have this equipment except for opacity monitors. Opacity monitors should be added in the replacement equipment costs if any oil-fired boilers or burners over 30 million Btu/h fuel input are planned for replacement in the evaluation procedure. The New Source Performance Standards require these monitors. The breaching and stack should be inspected for corrosion and possible replacement.

Information Management

Accumulation and management of historical operating data is an important byproduct from the control system. Historical data can be used to support operating reports, reports to regulatory agencies, to analyze operating problems, and to plan future improvements.

Operator Interface

Operators are the people who operate the plant on a day to day basis. It is very important that the control package provide operating information in a form that supports effective plant operation. The operator should be able to review the status and operating data of any instrument relevant to the operation of the unit. The information could be in the form of animated graphics, tabular report, or values shown on schematic flow diagrams or graphs.

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* Further information on these topics can be found in: McKinley et al. (1990); Michael, Retis, and Wreble (1992); Stoddard and Gill (1992); and Caple et al. (1992).

Fault Tolerance

Control Systems devices can and do fail. Control systems should be designed to be fault tolerant. Combustion control and flame safety systems must be implemented as isolated logic equipment to meet current NFPA safety code requirements.

Control Systems Technology

Microprocessor-based automation techniques are being used increasingly in many industrial processes. A wide variety of computerized systems packaged in different forms are available for the central heating plant. Selection of a system can be a trying process because of the many vendors and the quick pace at which digital hardware and software components are changing. In addition, determination of the control features and performance objectives require an analysis based on technical and cost considerations. The selection process must begin with an assessment and understanding of the existing boiler control needs so that a specification can be developed as a guide to vendors.

Control schemes used for these applications vary, ranging from a simple automatic feedback loop to multivariable control with feed forward and computational refinements. Conventional control concepts used in conjunction with advanced strategies, auto-tuning, and expert systems require digital technology. With these capabilities in place, a greater potential to increase boiler productivity can be realized as a consequence of tighter control. Because distributed control systems excel in the configuration and execution of process control algorithms, boiler regulatory control functions employ Distributed Control System (DCS) based controls. On-off type signals require high speed update times, 10 msec or better. Because of this criteria, Programmable Logic Controllers (PLCs), are currently used in boiler safety applications.

Recent technical advances have blurred the distinction between DCS and PLC systems. DCS manufacturers have improved discrete input/output (I/O) handling and logic capabilities while PLCs have enhanced process control capabilities. Control systems are packaged in a variety of configurations:

- Combustion Controller Unit: An advanced control system commonly implemented on small and medium size boilers. This package can include integrated oxygen and/or CO equivalent sensors to implement combustion control strategies based on a load demand signal. The system may be menu driven, self-contained, and may provide optional communication capabilities for interface with a PC. Equipment costs range between \$5,000–\$10,000.

- Single Loop Controller (SLC): Self-contained, standalone microprocessorbased controllers provide single loop integrity (where failure of one controller does not disable all others) and local auto-manual stations. These can be grouped to implement combustion control with cross limiting and feedforward; auto-tuning; digital I/0; proportional, integral, derivative (PID); and 3-element drum control. Controllers costs approximately \$2000/each. Typically two to four controllers are required per boiler, depending on requirements.

Single Loop Controllers shall be furnished with electronic bar graph indicators to display process variable, setpoint, and output values accurate to 1 percent of span. Process variable and setpoint shall also be available as digital display in engineering units. The SLC shall be equipped with remote setpoint capability, and configurable for direct/reverse action, PID gain parameters, remote/local mode operation, and manual output adjustment. A controller should be capable of accepting up to four 4-20 mA input signals and should be capable of developing a 4-20 mA output signal into loads up to 500 ohms. The controller shall also be able to accept up to three discrete (on/off) inputs and producing two discrete outputs.

Single Loop Controllers are manufactured by numerous vendors including Foxboro, Moore Products, C-E Taylor, Honeywell, Bailey, and Westinghouse. Supervisory control software residing on one or more Personal Computers can be linked to the controllers to provide operator graphics, alarms, reports, and historical data. Selection often depends on availability and communication drivers for the specific SLDC and PLC manufacturers.

- Distributed Control System (DCS): An integrated control system consisting of I/O devices, individual control processors, operator interfaces (such as a cathode-ray tube [CRT]), computers for data management, communication network, and an engineering work station. A DCS system performs sequencing functions, advanced control, alarming, trending, data storage, and reporting. The controllers are usually located in the process area connected to field instruments (inputs) and actuators (outputs). Data transfer is achieved via a high speed communication network to a work station and/or an operator interface. System costs can be expensive ($50,000–$150,000 or more). DCS vendors realize their high entry costs and have begun to address this issue by offering lower cost starter systems ($30,000 – $50,000) The higher entry costs limit application to larger boiler complexes.

- PLC: Programmable Logic controller, a microprocessor-based special purpose computer that is programmed to perform interlock control functions, primarily to replace relays and electro-mechanical devices. Design extensions and refinements have enhanced their PID control, however not as effectively as in DCS systems. Major vendors include Allen-Bradley, Texas Instruments, and Modicon. Costs are generally less than DCS.

- PC-Based System: A system that uses a personal computer with third-party control software to provide operator graphics, operating reports, and a historical log. PC-based systems can interface with PLCs, unit controllers, SLCs and DCS systems (Appendix C shows a typical PC-based control system network). These systems are cost effective and flexible. System functions are similar to DCS systems and include data collection, PID, advanced control, alarming, and operator interface. Costs include: Computer Equipment ($5,000 each) and software ($5,000 – $10,000 each).

  Additional systems integration costs can be expected to range from $20,000 to $100,000 or more. Personal Computer-based control systems software is generalized to be applicable to just about any chemical, mechanical, electrical or electronics manufacturing unit. These packages can interface with a variety of SLC and PLC hardware. Major vendors include:

- FIX DMACS by Intellution, Inc.
- Paragon by Intec Controls
- Onspec by Heuristics, Inc
- LT Control/Labtech Notebook by Laboratory Technologies
- Genesis by Iconics, Inc.
- CIM-PAK by Action Instruments.

The controllers and software listed above are highly flexible products that must be adjusted to individual circumstances. The mere purchase and installation of this equipment does not create a control system; there is a matter of design and configuration. Responsibility and liability for the design and configuration of these controls must be established in contract documents.

Field Instruments

Proper selection and sizing of field instruments are crucial to any control system upgrade. They are the "eyes," "ears," "arms," and "legs" of the control system. Broad guidelines are listed below for instrument selection criteria.

- Instrument signals: Typically 2-wire 4-20 mA DC with a load resistance of 250 ohms, or pneumatic 3-15 psig.* Electric and pneumatic signals can be easily converted. Actuators may be either electric or variable speed drives but are often pneumatic. Instrument signals rely on the availability of electrical supply (typically 24 Vdc) and/or instrument air (typically 80-100 psig). Loss of signal conditions must be evaluated.

- Materials of construction: Must be compatible with the environment and process fluids involved in the application. This often implies use of 316 stainless steel in many power plant applications.

- Process conditions such as pressure, temperature, flow rate, vibration, and ambient conditions must be specified for all modes of operation including start-up, normal operation, abnormal operation, and shutdown.

- Level transmitters: Many options exist, including differential pressure (DP), float, conductive or capacitive type. Selection depends on the type of process involved. Accuracies vary among the technologies, but 0.5 percent of span is reasonable for most applications. DP transmitters must consider suppression and elevation (i.e., 150 percent of range), and the potential for over-pressurization.

- Pressure transmitters are available to 0.1 percent accuracy, repeatability, and hysteresis.

* psig = lb/sq in. gage; 1 sq in. = 6.452 cm^2.

- Flow transmitters are available in various types:

  - Differential Pressure flow transmitters measure the pressure loss across a flow element, similar to a DP level transmitter, except that a square-root signal must be calculated either in the transmitter, or in the receiving instrument. DP transmitters are often used for steam and condensate, natural gas, and other flows. DP flow transmitters are restricted to a 4:1 turndown based on accuracy.

  - Turbine meters are often used for fuel oil. They exhibit a 0.5 percent accuracy with a 10:1 turndown.

  - Mass flow meters are used for stack gas and fuel flow measurement, and exhibit a 1 percent accuracy and 10:1 turndown.

  - Vortex meters are gaining favor as a reliable method to measure flow of water, steam and other fluids. They exhibit high accuracies and deep turn down (20:1).

- Temperature is normally measured using Resistance Thermal Devices (RTDs) or thermal couples. These may be read directly by some DCS or PLC controllers or transformed to a 4-20 mA signal for use by other controls. Accuracy can be as low as 0.2 °F (°F = [°C × 1.8] + 32).

- Control valves must be selected and sized for each application. Numerous valve designs exist to cope with the variety of fluids, contaminates, flow rates, and temperatures. High pressure drops may cause cavitation, noise, and wear and therefore require particular care in specifying and sizing. Materials selection is particularly important for resistance to corrosion and erosion.

4 Developing Budget Proposals

Introduction

This chapter presents control system guidelines and procedures for preparing budget proposal recommendations. Appendix D includes a sample proposal form in five parts:

1. Plant Description: A brief description of the plant and its service requirements.

2. Unit Benefits Estimate: Potential cost savings are identified on *one* form for *each* Fuel for *each* Boiler. Other noncost benefits are also identified in the categories provided.

3. Unit Cost Estimate: *One* form for *each* boiler.

4. Balance of Plant Cost Estimate.

5. Summary.

Part 1: Plant Description

This form is used to list boiler ratings, fuel types, year of construction, major refurbishments, and existing boiler control systems installed or planned for the facility. Space is also provided to describe service requirements, anticipated load changes, and any applicable environmental constraints.

Part 2: Unit Benefits Estimate

These forms are used to estimate potential energy savings. *Submit one form for each fuel on each unit evaluated.* Where possible, consider data from the last 3 years. Noncost information will also be considered in the evaluation. Part 2 provides an opportunity to discuss the following issues:

- Obsolescence: This typically occurs when the manufacturer of the equipment no longer supports the supplied system with the spare parts necessary to keep the instrumentation and control system performing at acceptable levels. Additionally, the original equipment manufacturer may no longer be in business.

- Excessive Maintenance: The most common occurrence of this is when the equipment requires a constant "tweaking." Where the sum of the yearly cost of nonroutine maintenance exceeds 15 percent of the device, system, or new purchase price, replacement should be considered. Abnormal maintenance is defined as when specific people with very specialized training are required to maintain or service the equipment. Indications of excessive maintenance are instruments requiring more than yearly calibration, devices that require the same maintenance more than once per year, controllers and positioners that require constant tuning, etc.

- Safety: Environmental regulations now require replacement of equipment that used or contained Mercury and/or other hazardous material. Additional safety concerns are recognized when existing systems cannot support the latest NFPA requirements.

- Multiple Unit Compatibility: This is defined as when a facility has several different units, each having controls that are incompatible to other units within the same facility. For instance, Unit 1 could be an older pneumatic version; Unit 2 has a newer version of pneumatics (maybe the Manual/Auto station has bumpless transfer); Unit 3 has electronics from one manufacturer with -10-0+10 volt signals and Unit 4 has electronics with 0-10 V DC signals.

- Efficiency: Many articles have been written in control magazines supporting a 10 percent savings in fuel cost by upgrading the control systems and oxygen trim. Additional efficiencies can be achieved with multi-unit plants by putting as many units as possible into each unit's most desirable load range where they have highest efficiencies (Jones 1987; Econics 1979).

Part 3: Unit Cost Estimate

Select the appropriate cost estimating form in Appendix C for the size of the unit under consideration. Review serviceability of existing field instruments to determine if replacement costs should be listed (replace if the existing transmitter is pneumatic or does not produce 4-20 mA electronic signal).

For developing budgetary numbers, a typical system of individual single loop controllers linked to a PC system was chosen. This includes a communication controller and "standard" PC software with operator screens, performance monitoring, and user defined reports.

Part 4: Balance of Plant Cost Estimate

This form is used to estimate control system costs for common plant equipment such as water treatment systems, sootblowers, cooling towers, air compressors, electrical switchgear, and pollution control systems. For cost-estimating purposes, identify the number of inputs and outputs (I/O) desired to be monitored for each ancillary system.

Part 5: Summary

Control system costs are summarized for units and balance of plant. Payback is calculated using a simple Net Present Value (NPV) method for a "rough" economic evaluation. The NPV factor is calculated based on:

$$K_{NPV} = \sum_{i=1}^{n} \frac{1}{(1+\ rate)^{i}} \qquad \text{[Eq 1]}$$

The factor listed in Part 4 is based on a discount/interest rate of 8 percent and an 8-year payback, assuming a uniform savings throughout the 8-year period. This factor can be adjusted for specific economic conditions by substituting another interest rate:

$$K_{NPV} = \sum_{i=1}^{8} \frac{1}{(1+\ 0.08)^{i}} = 5.747 \qquad \text{[Eq 2]}$$

Merits of the proposed control system upgrade will consider the economic payback as well as the other benefits listed in Part 2.

5 Monitoring Contract Performance

Monitoring of Engineer contractor performance is accomplished with a very detailed approach to the project with regular and established communications, good facility participation, and strict adherence to the installations as shown on the submitted contract documents. A list of typical design tasks is provided in Appendix E.

The Engineer and/or contractor selected to perform the facility upgrade shall be required to prepare the following documents (samples provided in Appendix F):

- Data Sheets: Data Sheets shall be in the ISA (Instrument Society of America) format with at least one sheet per device.
- Installation Diagrams: Each instrument and/or device shall be referenced to a specific installation diagram that details materials and components (valves, tees, fittings, etc.) by relative location and part numbers.
- Loop Diagrams: Each instrument and/or device shall be shown on a loop diagram. The loop diagram shall contain field wire numbers, device log numbers, software addresses, calibration data, device model numbers, and field wiring terminations. Loop diagrams shall indicate, where possible, the field device generating a control signal, the functional controller, and the field device that changes state because of the original input. These diagrams shall conform to ISA criteria.
- Instrument/Device List: This shall be a computer-generated listing using dBase (a product of Ashton-Tate [Borland International]) or other "standard" data base systems. This listing shall contain the instrument/device number, the service of the instrument/device, the model number, range, operating point, installation diagram reference, and loop diagram references.
- SAMA Diagrams (Scientific Apparatus Makers Association): SAMA diagrams shall conform to the latest issue of ISA Standards and Procedures.
- Contract Format: It is recommended that *one* contract be issued. The selected contractor must demonstrate expertise and capabilities necessary to perform the instrument and control scope and any additional plant modifications as found in the evaluation procedure.
- Schedule: The contractor shall, before mobilization, submit a construction schedule having fewer than 30 activities. The schedule shall show duration of activities and anticipated manpower resources. This schedule shall be upgraded at least monthly and more often as required by the Heat Plant facility. The schedule shall be presented in a bar graph form.

- Submittals: The selected contractors shall make formal submittals of instruments/devices, wire conduit, tubing and fittings, control panels, panel devices, and other materials as required.

- Safety: The contractor shall submit for review a safety manual to be used on the construction site.

- Start-up: The contractor, in his original proposal, shall detail calibration loop checkout and start-up procedures that will be used in this project. Additionally, the contractor shall, in his proposal, supply the manhours allocated to these activities.

- Warranties: The contractor shall assume, as part of their contact scope, a 1-year warranty on instruments, instrument installation, panel construction, and quality of craftsmanship from the time of owner acceptance.

6 Summary and Recommendations

These guidelines provide a brief introduction to boilers, and boiler control systems. A step-by-step approach is provided for developing budgetary cost proposals. Insights are provided for monitoring subsequent engineering and contractor performance. Basic conditions that may be used justify a control systems upgrade include:

- the need to restore existing units to meet load growth
- a significant change in operating conditions for an existing plant
- the reliability and availability of new control technologies
- the need to comply with environmental or safety regulations
- a need to take advantage of better operating and maintenance economies.

Three alternatives for addressing these conditions are:

1. *Repair existing controls.* Use this approach to restore existing control capabilities where spare parts are readily available and where safety regulations and economics do not justify broader changes. Control System costs are typically less than $25,000 (1993 dollars).

2. *Upgrade existing controls.* Use this approach where spare parts, safety, or operating economics justify change-out of controls. In addition, mechanical work such as burner replacement or other repair/replacement may be necessary to meet precepts of these guidelines. Control System costs are normally expected to be under $300,000 (1993 dollars).

3. *Install new or replacement boiler.* Use this approach where existing boiler equipment is no longer serviceable, or where additional capacity is needed.

These guidelines, by their nature, are general. They provide basic information to evaluate feasibility of upgrading boiler control systems and a methodology for developing budget proposals. Judgement must be applied to develop designs to meet specific unit and site characteristics, boiler safety codes, and local regulatory requirements.

These guidelines do not eliminate the need for competent professional engineers to finalize assessments of existing conditions, to develop a plant control system design that meets existing and new requirements, and to evaluate alternative Contractor proposals. These control system guidelines should be applied only where the mechanical fitness, or cost to restore mechanical fitness, of the boiler, burners, and associated equipment has been established.

It is recommended that the information presented in this report be disseminated in a Design Guide (DG). It is also recommended that the system selection guidelines be incorporated into installation training programs for heating plant personnel, facility engineers, and utility supervisors. Such guidelines would benefit U.S. Army Corps of Engineers Districts responsible for heating plant design and construction.

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Appendix B: Guidelines for Selection of Combustion Controls

Guidelines are provided for the selection of combustion controls, drum level controls, and related field instruments. Guidelines summarized in Table B1 include references for combustion control strategies as shown in:

- Figure B1 Jack Shaft Control (with optional O_2 trim configuration)
- Figure B2 Parallel Positioning Control (with optional O_2 trim configuration)
- Figure B3 Metered Control.

References are also provided in Table B1 for drum level control strategies as illustrated in:

- Figure B4 Single Element Feed Water Control
- Figure B5 Two Element Feed Water Control
- Figure B6 Three Element Feed Water Control.

Control strategy notation is summarized in Figure B7, "Controls Notation."

The guidelines are intended to be general. Requirements will vary, depending on the specific boiler configuration and site requirements. For boilers at the upper or lower end of a given size range, consider the guidelines for the adjacent size range.

Combustion control systems are designed to operate in conjunction with, but subordinate to the boiler flame safety system. The flame safety system should be examined for conformance to current NFPA code. The flame safety system will likely need to be upgraded or changed out if installed before 1980.

Boiler control systems are typically implemented in microprocessor-based controllers or single loop controllers today. Smaller plants (i.e., one to four boilers) will likely use single loop controllers (SLCs). Larger plants may find that distributed control systems (DCSs) better fit overall plant requirements. Either approach falls within these guidelines. A conceptual network for single loop controllers is shown in Figure B8. Typically, a boiler may be controlled either from the single loop controllers or remotely via personal computer-based CRT monitors. The supervisory computers provide a cost effective centralized operator "control panel" that can display status of the boiler and its alarms graphically in real time. The personal computer also provides an excellent method to log historical data for purposes of generating operating reports and analyzing operational or maintenance conditions.

A DCS equipment approach provides similar capabilities for larger scale plants. The structure of each DCS system depends on vendor characteristics, but conceptually performs similar functions (Figure B8).

A list of candidate inputs to the PC monitoring system and controlled outputs from the PC monitoring system are provided in Table B2 for typical boiler and Table B3 for overall plant auxiliary devices. This list provides a reference for additions or deletions depending on specific plant requirements.

Table B1. Boiler control guidelines.

Unit Size	Small Fire Tube 1K - 15K pph	Medium Return Water Tube 10-40K pph	Large Water Tube 40-300K pph
Boiler Control			
Combustion Controls Type	Jack Shaft (Figure C-1)	Parallel Positioning (Figure C-2) (1)	Parallel Meter (Figure C-3)
Fuel/Air Trim	None - Quarterly Calibration	O_2 (2)	O_2/CO (3)
Drum Level:			
Single Element	Yes		
Two Element		Alt (4)	
Three Element		Yes	Yes
Boiler Master	Yes	Yes	Yes
Boiler Instruments (Analog Signals)			
Steam Flow	Yes	Yes	Yes
Steam Pressure	I	R	R
Feed Water Flow	R	R	R
Feed Water Temperature	I	R	R
Drum Level (s)	I	R	R
Feed Water Valve	Yes	Yes	Yes
Condensate Return Temperature	I	R	R
Boiler Makeup Water Flow	I	R	R
Gas and/or Oil Flow	I	R	R
Fuel Oil Pressure	I	I	R
Air Flow	NA	R	R
FD Fan Damper (or Jack Shaft) Positioner	Yes	Yes	Yes
Oxygen Meter	No	Yes	Yes
Opacity Meter	R (oil)	No	Yes
Boiler Exit Flue Gas Temperature	R	R	R
Flue Gas Draft	NA	I	R
Flue Gas Temperature	NA	I	R
Combustion Air Temperatures (Note 7)	NA	I-R	I-R
Combustion Air Pressure (Note 7)	I	I	I
Plant Instrumentation & Control			
Plant Master Controller (Note 8)	Yes	Yes	Yes
Plant Steam Pressure	R	R	R
Plant Steam Flow (s)	I	R	R

Notes:
(1) Jack Shaft Controllers may be used in smaller units.
(2) O_2 trim may not be justifiable in smaller units. Substitute quarterly calibration tests in these cases.
(3) CO trim may not be economical except in larger units.
(4) Drum Level: Use 3-element for small capacity drum or where rapid demand changes can occur.
(5) Locations - Furnace, Boiler Outlet, Air Heaters(2), Economizer(2), Air Pollution Control(2), and I.D. Fan(2)
(6) Locations - Boiler Outlet, Air Heaters(2), Economizer(2), Air pollution Control(2), and I.D. Fan(2)
(7) Locations - F. D. Fan Outlet, Air Heaters(2), Windbox
(8) Plant Master required for multiple boiler installations

Legend: T = Totalize, I = Indicate, R = Record, NA = Not Applicable.

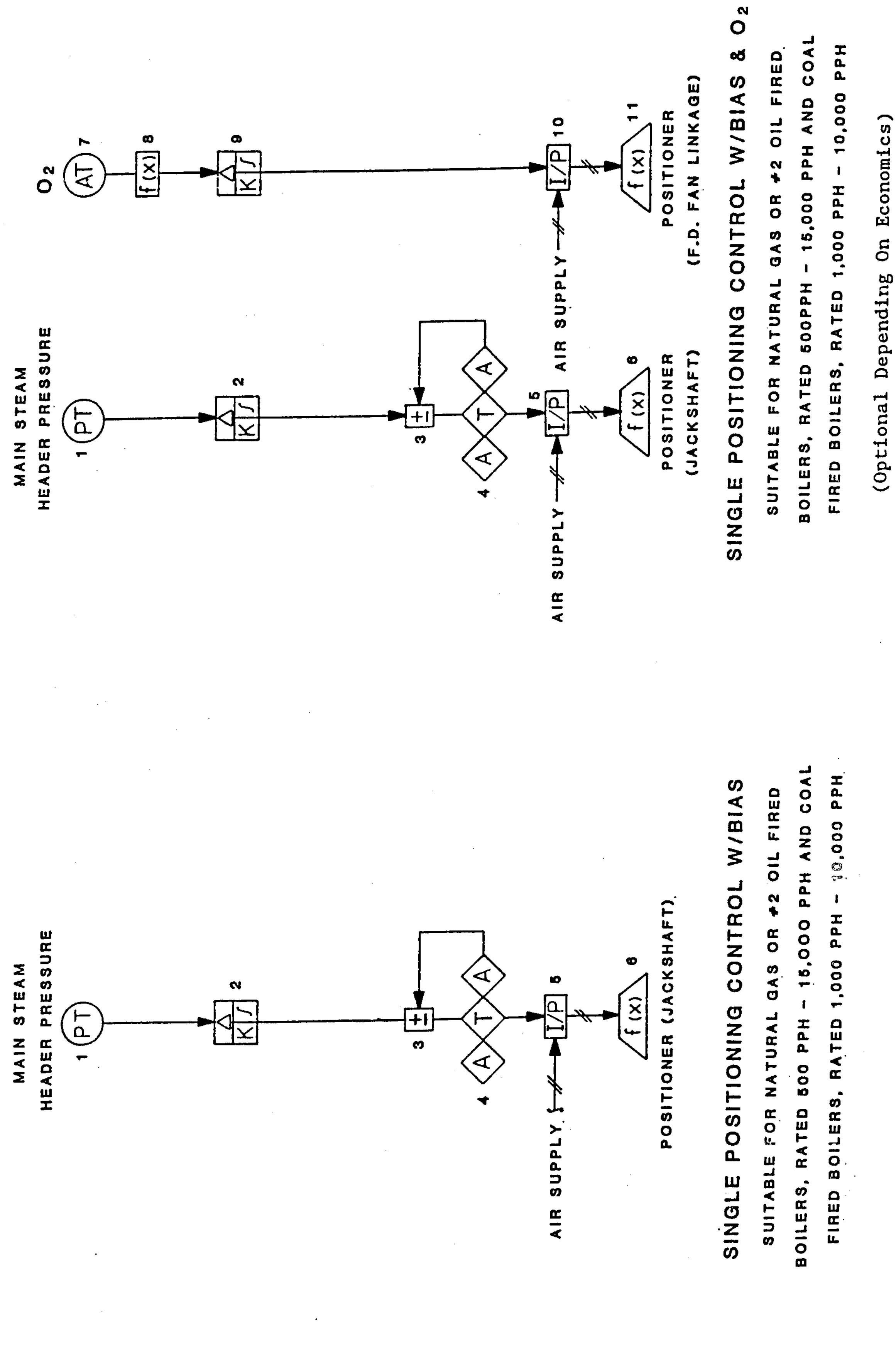
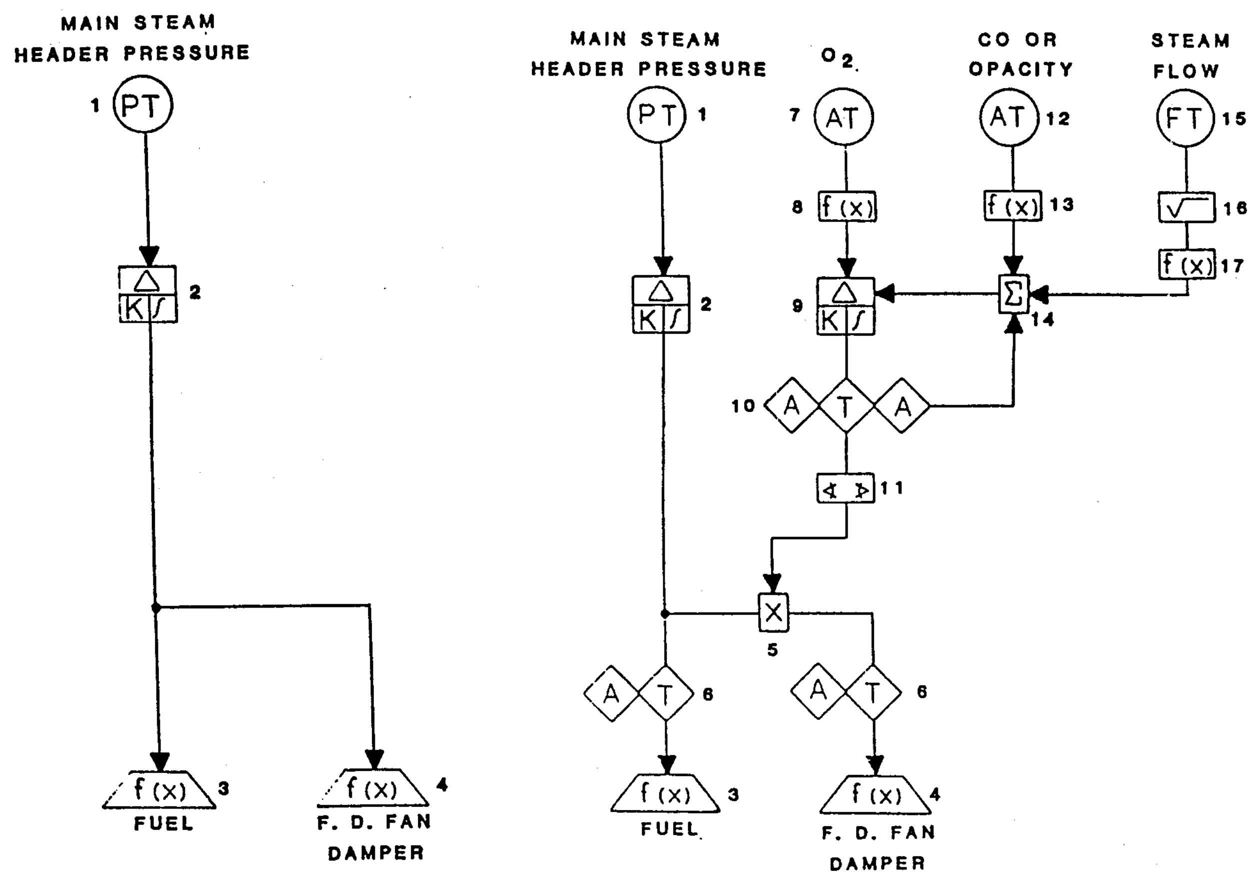


Figure B1. Jackshaft control.



BASIC PARALLEL POSITIONING CONTROL

SUITABLE FOR NATURAL GAS OR # 2 OIL FIRED BOILERS,
RATED 5,000 PPH TO 50,000 PPH AND COAL FIRED BOILERS.
RATED 3,000 PPH TO 50,000 PPH.

PARALLEL POSITIONING CONTROL W/ RATIO, O_2 TRIM, CO OF OPACITY TRIM & STEAM FLOW

SUITABLE FOR NATURAL GAS OR # 2 OIL FIRED BOILERS,
RATED 5,000 PPH TO 50,000 PPH AND COAL FIRED BOILERS,
RATED 3,000 PPH TO 50,000 PPH.

(Optional Depending On Economics)

Figure B2. Parallel positioning control.

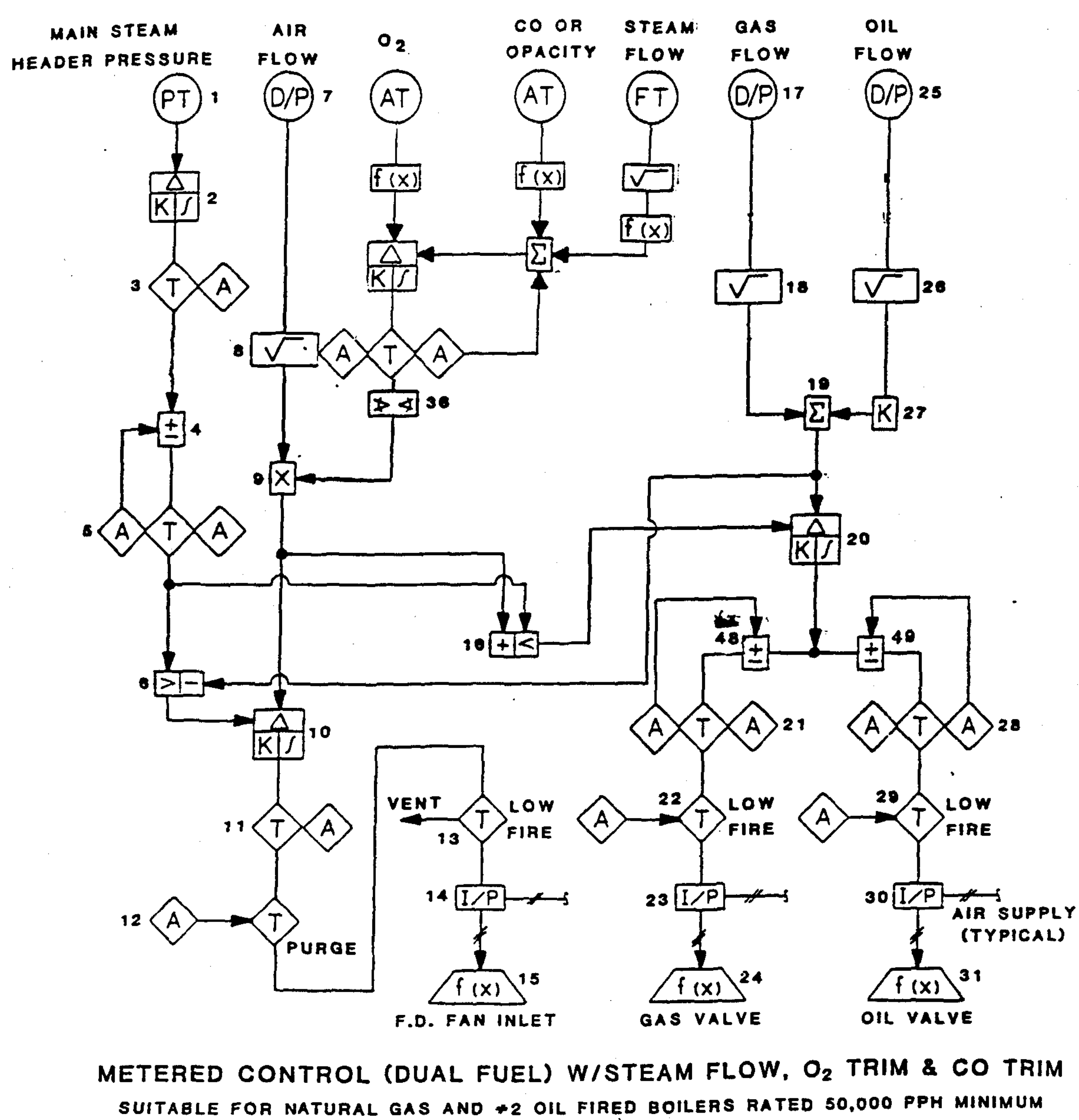
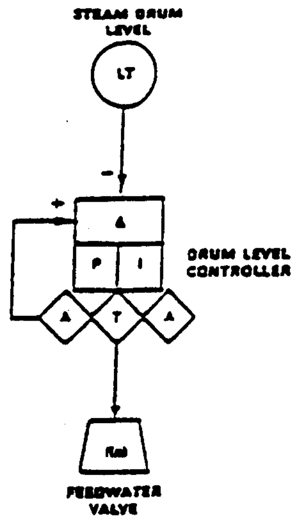
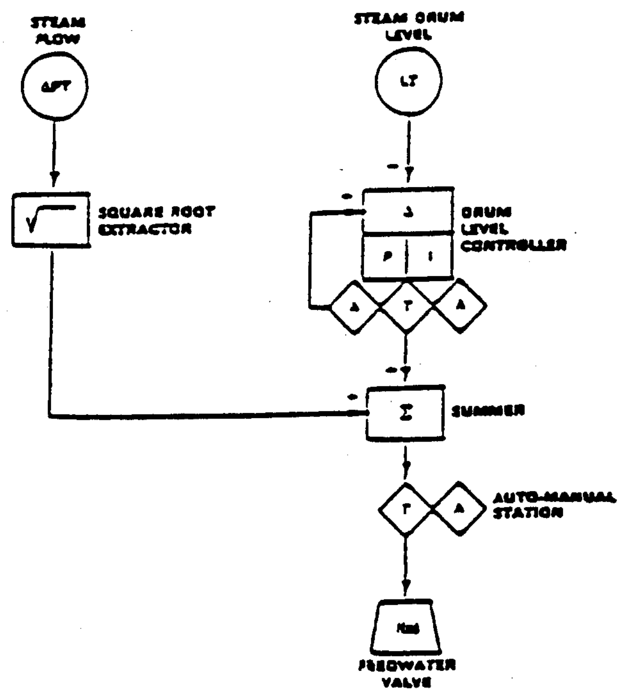


Figure B3. Metered control (dual fuel) with steam flow, O_2 trim, and CO trim.



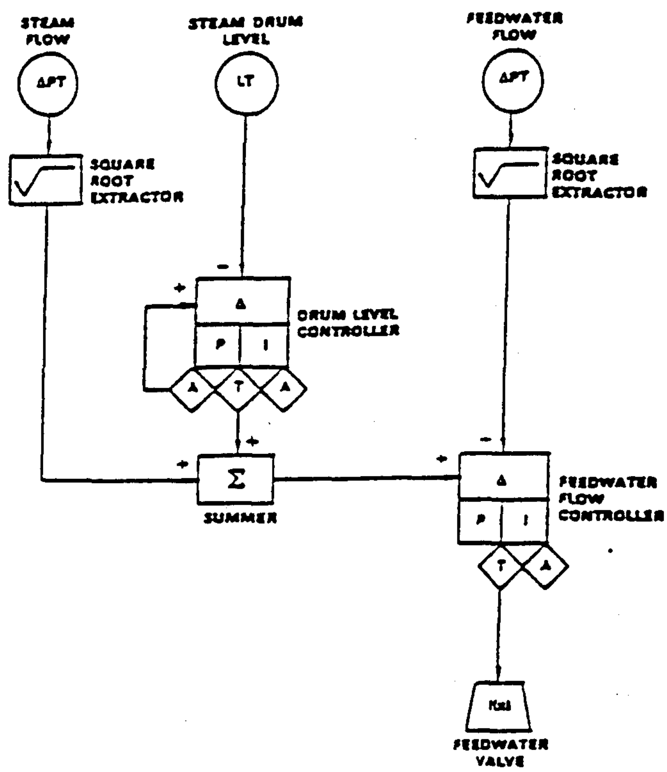
Single-element feed water control measures the variation in the steam drum water level, compares that to the setpoint (normal water level), and positions the feed water control valve to maintain water level. The single-element feed water control is only used where a large volume of water storage and small load demand changes are present (i.e., firetube boilers).

Figure B4. Single-element feed water control.



Two-element feed water control uses the steam flow signal as a feed forward signal added to the drum water level. The change in steam flow will cause an immediate change in the signal to the control valve to maintain the proper water level. After steam flow stabilization, the drum level water controller will maintain the proper water level. This type of control action will minimize the effect of shrink and swell during load changes, and is recommended on all water-tube boilers. (Note: The steam flow signal does not affect the signal during stabilized operating periods.)

Figure B5. Two-element feed water control.



Three-element feed water control uses an additional controller. Inputs are feed water flow and the two element control signal (cf. Figure B5). These values are compared and the action maintains feed water flow equal to steam output. The feed water flow is the variable input to the controller and thus will maintain drum level over varying steam load changes, elininating shrink and swell effects. This control is used on large boilers haveing small steam drums, or when very large and rapid steam demand changes are present.

Figure B6. Three-element feed water control.

Δ / K ∫	THIS SYMBOL DENOTES A CONTROLLER WITH GAIN OR PROPORTIONAL BAND ADJUSTMENT PLUS RESET FUNCTION.
Δ	THIS SIGN IS THE DIFFERENCE SEEN BY THE AMPLIFIER BETWEEN A SET POINT SIGNAL AND A FEEDBACK SIGNAL.
K	THIS SIGN IS THE GAIN ADJUSTMENT OF THE OUTPUT SIGNAL FROM THE DIFFERENCE AMPLIFIER.
∫	THIS SIGN DENOTES RESET FUNCTION WHICH KEEPS THE OUTPUT SIGNAL MOVING UNTIL THERE IS NO DIFFERENCE ACROSS THE AMPLIFIER.
×	THIS SYMBOL DENOTES A RATIO MULTIPLIER USED TO RATIO AN INPUT SIGNAL TO THE OUTPUT SIGNAL. CAN BE A MANUAL-ADJUSTED RATIO OR CAN BE ADJUSTED FROM AN EXTERNAL CONTROL SIGNAL INPUT.
f (x)	THIS SYMBOL IS A FIELD-ADJUSTABLE SLOPE CHANGER OR RATIO DEVICE USED IN THE CALIBRATION OF A SYSTEM.
A T	THIS SYMBOL DENOTES A TRANSFER STATION FROM AUTOMATIC TO MANUAL.
A T A	THIS SYMBOL DENOTES AN AUTO/MANUAL TRANSFER STATION WITH LOCAL SET POINT TO A CONTROLLER, OR A BIAS, OR SUMMER.
Σ	THIS SYMBOL IS A SUMMER THAT SUMS UP ALL INPUT SIGNALS AND TRANSMITS A SIGNAL EQUAL TO THE SUM OF THE INPUTS.
√‾	THIS SYMBOL DENOTES A SQUARE ROOT EXTRACTOR THAT EXTRACTS THE SQUARE ROOT OF AN INPUT SIGNAL. THIS IS NECESSARY TO OBTAIN A FLOW SIGNAL FROM A D/P TRANSMITTER.
I/P	THIS SYMBOL DENOTES A CONVERTER WHICH TRANSLATES A MILLIAMP SIGNAL TO A PNEUMATIC OUTPUT.
f (x)	THIS SYMBOL DENOTES A FINAL DRIVE ELEMENT. CAN BE ELECTRIC OR PNEUMATIC. OPERATING A DAMPER, INLET VANES, OR VALVES.
< >	THIS SYMBOL DENOTES A HIGH-LOW LIMITER. CAN BE USED TO LIMIT THE HIGH LEVEL OR LOW LEVEL OF A CONTROL SIGNAL PASSING THROUGH IT.

Figure B7. Controls strategy notation.

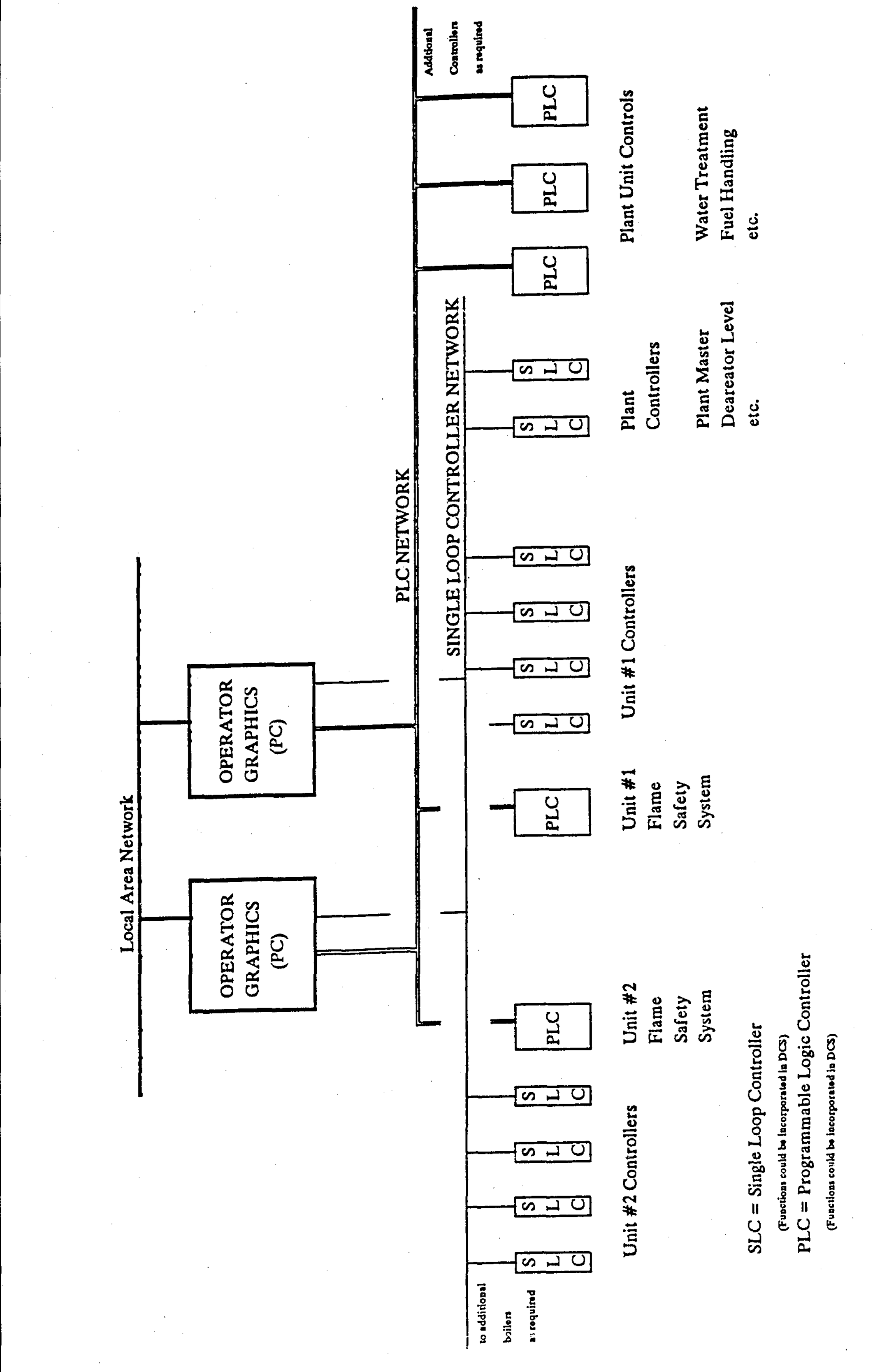


Figure B8. Typical boiler plant control network.

Table B2. Candidate monitoring and control points for individual boiler (typical points, adjust for specific number of services on the boiler).

	I/O Type	Quantity
UNIT NO. _ CONTROL POWER STATUS	DI	_
UNIT NO. _ FD FAN DAMPER OPERATOR	AO	_
UNIT NO. _ FD FAN RUN STATUS	DI	_
UNIT NO. _ FEED WATER FLOW	AI	_
UNIT NO. _ FLAME FAILURE TRIP	DI	_
UNIT NO. _ FLUE GAS OXYGEN	AI	_
UNIT NO. _ FLUE GAS CO	AI	_
UNIT NO. _ FLUE GAS TEMPERATURE	AI	_
UNIT NO. _ FUEL FLOW CONTROL (GAS/OIL)	AO	_
UNIT NO. _ FUEL OIL FLOW	AI	_
UNIT NO. _ FUEL OIL PRESS TRIP	DI	_
UNIT NO. _ FUEL OIL PRESSURE	AI	_
UNIT NO. _ HIGH NATURAL GAS PRESS ALARM	VI	_
UNIT NO. _ HIGH NATURAL GAS PRESS TRIP	DI	_
UNIT NO. _ HIGH STEAM DRUM LEVEL ALARM	VI	_
UNIT NO. _ HIGH STEAM DRUM LEVEL TRIP	DI	_
UNIT NO. _ HIGH STEAM DRUM PRESS TRIP	DI	_
UNIT NO. _ LOW ATOM AIR PRESS TRIP	DI	_
UNIT NO. _ LOW ATOM AIR PRESSURE ALARM	DI	_
UNIT NO. _ LOW COMPRESS AIR PRESS TRIP	DI	_
UNIT NO. _ LOW FD FAN AIR PRESS TRIP	DI	_
UNIT NO. _ LOW FLUE GAS OXYGEN	VI	_
UNIT NO. _ LOW FUEL OIL PRESSURE ALARM	DI	_
UNIT NO. _ LOW NATURAL GAS PRESS ALARM	DI	_
UNIT NO. _ LOW NATURAL GAS PRESS TRIP	DI	_
UNIT NO. _ LOW STEAM DRUM LEVEL ALARM	VI	_
UNIT NO. _ LOW STEAM DRUM LEVEL TRIP	DI	_
UNIT NO. _ NATURAL GAS FLOW	AI	_
UNIT NO. _ NATURAL GAS PRESSURE	AI	_
UNIT NO. _ NATURAL GAS/FUEL OIL SELECT	DI	_
UNIT NO. _ ON	DI	_
UNIT NO. _ STEAM DRUM LEVEL	AI	_
UNIT NO. _ FEED WATER CONTROL	AO	_
UNIT NO. _ STEAM FLOW	AI	_
UNIT NO. _ STEAM TEMPERATURE	AI	_
UNIT NO. _ STEAM TEMPERATURE CONTROL	AO	_
UNIT NO. _ CONDUCTIVITY	AI	_

I/O Legend: DI = Discrete Input, DO = Discrete Output, I = Analog Output, VI = Virtual Input (derived in logic)

Table B3. Candidate monitoring and control points for heating plant auxiliary points (typical points, adjust for specific number of pumps or devices).

	I/O Type	Quantity
AIR PRESSURE LOW	DI	_
AIR COMPRESSOR NO. _ RUN STATUS	DI	_
BOILER FEED PUMP NO. _ AUTO STATUS	DI	_
BOILER FEED PUMP NO. _ RUN STATUS	DI	_
BOILER FEED PUMP NO. _ START	DO	_
BOILER FEED PUMP NO. _ STOP	DO	_
BOILER FEED PUMP NO. _ TRIP	VI	_
COMPRESSED AIR LOW PRESSURE	DI	_
CONDENSATE PUMP NO. _ AUTO STATUS	DI	_
CONDENSATE PUMP NO. _ RUN STATUS	DI	_
CONDENSATE PUMP NO. _ START	DO	_
CONDENSATE PUMP NO. _ STOP	DO	_
CONDENSATE PUMP NO. _ TRIP	VI	_
CONDENSATE PUMP ROOM SUMP HIGH LEVEL ALARM	DI	_
CONDENSATE RECEIVER HIGH LEVEL ALARM	VI	_
CONDENSATE RECEIVER LEVEL	AI	_
CONDENSATE RECEIVER LOW LEVEL ALARM	VI	_
CONDENSATE RECEIVER LOW LEVEL TRIP	DI	_
DEAERATOR HIGH TEMPERATURE	VI	_
DEAERATOR HIGH WATER LEVEL ALARM	VI	_
DEAERATOR HIGH WATER LEVEL TRIP	DI	_
DEAERATOR LOW TEMPERATURE	VI	_
DEAERATOR LOW WATER LEVEL ALARM	VI	_
DEAERATOR LOW WATER LEVEL TRIP	DI	_
DEAERATOR PRESSURE	AI	_
DEAERATOR TEMPERATURE	AI	_
DEAERATOR WATER LEVEL	AI	_
FUEL OIL PUMP NO. _ RUN STATUS	DI	_
MAIN STEAM HEADER PRESSURE	VI	_
MAIN STEAM HEADER PRESSURE HIGH ALARM	VI	_
MAIN STEAM HEADER PRESSURE LOW ALARM	VI	_
MISCELLANEOUS DCS, PLC DIAGNOSTICS	VI	_

Legend: DI = Discrete Input, DO = Discrete Output, I = Analog Output, VI = Virtual Input (derived in logic)

Appendix C: Proposal Forms

HEATING PLANT CONTROLS UPGRADE PROPOSAL
PART 1 PLANT DESCRIPTION

Plant & Location: ____________
Date: ____________

UNIT DATA

	SIZE	PRESS	FUEL	EXISTING CONTROLS[1]	INSTALL DATE	DATE of LAST OVERHAUL	MECHANICAL CONDITION[2]	EXIT FLUE GAS TEMPERATURE
Unit No. ____								
Unit No. ____								
Unit No. ____								
Unit No. ____								
Unit No. ____								
Unit No. ____								

SERVICE REQUIREMENTS - Briefly describe types of loads served (size, variability, criticality, expected future load changes, environmental constraints, etc.)

Attach supplemental documents as necessary to address these questions
1. Controls Manufacturer and Model Number.
2. List any known mechanical deficiencies such as burners, excessive air infiltration, boiler tube failure, fan problems, etc.

HEATING PLANT CONTROLS UPGRADE PROPOSAL
PART 2 BENEFITS

(Submit one sheet per boiler and per fuel if dual fired)

Boiler#___
Fuel#___ (gas, oil, other ______________) circle one

Location & Plant: __________
Date: __________

POTENTIAL UNIT ENERGY SAVINGS calculations are listed by column number, in footnotes, below.

Load Range	(1) Average Load Fraction	(2) Operating Hours Per Year	(3) Maximum Capacity MBTU/HR	(4) Fuel Cost $/MBTU	(5) Fuel Cost $/Year	(6) Actual % O_2	(7) Target %O_2	(8) Δ %O_2	(9) Approximate % Efficiency Improvement
10-40%	0.25								
40-60%	0.50								
60-85%	0.725								
85-100%	0.925								

Annual Total Hrs.[2T] ______ (Max 8760)   Total Annual Fuel Cost[5T] $______   % Efficiency Improvement[9T] ______

Cost Savings[10] $______

Energy Savings[11] ______ (MBTU/Year)

Notes: Calculations for columns (by column number):

(2T) = Sum of column (2) = Operating Hours Per Year
(5) = (1) x (2) x (3) x (4) = Fuel Cost $/Yr
(5T) = Sum of column (5) = Total Annual Fuel Cost
(8) = (6) - (7) = %O_2 improvement
(9) = (2) ÷ (2T) x (8) = Approximate Efficiency Improvement
(9T) = Sum of column (9) = % Efficiency Improvement
(10) = (5T) x (9T) ÷ 100 = Cost Savings
(11) = (10) ÷ (4) = Potential Energy Savings

MAINTENANCE HISTORY - Briefly describe control systems maintenance activity, spare parts availability, manufacturer support, etc.)

SAFETY - Briefly describe any known safety issues such as compliance with current codes.

FUTURE CONTROL SYSTEM - Briefly describe features of control system envisioned.

Attach additional supporting information as necessary.

HEATING PLANT CONTROLS UPGRADE PROPOSAL
PART 3 SMALL UNIT COST ESTIMATE (One per Boiler)

ITEM	UNIT COST	QTY	COST EST
Jack Shaft Drive Unit	$4,375	___	______
Control Valves:			
Feed water	$3,125	___	______
Gas	$3,125	___	______
Oil	$3,125	___	______
Transmitters:			
Drum Level	$1,250	___	______
Steam Pressure	$1,125	___	______
Flow Meters:			
Feedwater	$2,500	___	______
Steam	$2,500	___	______
Gas	$2,500	___	______
Oil	$2,500	___	______
Oxygen Analyzer & Controller (see Note 1)	$9,375	___	______
Controllers:			
Steam Pressure	$2,500	___	______
Drum Level	$2,500	___	______
Pressure & Temperature Gages (1 lot)	$2,500	___	______
Multipoint Recorder	$2,500	___	______
Annunciator	$2,500	___	______
Control Panel & Miscellaneous Indicators	$12,500	___	______
Flame Safety System:			
Operator interface and logic unit	$12,500	___	______
Gas Safety valves	$3,125	___	______
Oil Safety valves	$3,125	___	______
Fuel pressure switches	$625	___	______
Drum Level Hi/Lo & Lo Cutoff switches	$1,125	___	______
Miscellaneous Other Unit Instrument Costs:			
	SUBTOTAL:		______

Note 1: Oxygen trim is optional depending on potential economic benefit.

HEATING PLANT CONTROLS UPGRADE PROPOSAL
PART 3 MEDIUM UNIT COST ESTIMATE (One per Boiler)

ITEM	UNIT COST	QTY	COST EST
FD Fan Damper Drive	$8,458	___	______
Control Valves:			
Feed water	$6,041	___	______
Gas	$6,041	___	______
Oil	$6,041	___	______
Transmitters:			
Drum Level	$1,250	___	______
Steam Pressure	$1,125	___	______
Flow Meters:			
Feedwater	$2,500	___	______
Steam	$2,500	___	______
Gas	$2,500	___	______
Oil	$2,500	___	______
Oxygen Analyzer	$9,375	___	______
Controllers:			
Steam Pressure	$2,500	___	______
Gas	$2,500	___	______
Oil	$2,500	___	______
Drum Level	$2,500	___	______
Air Flow	$2,500	___	______
Oxygen Trim	$2,500	___	______
Pressure & Temperature Gages (1 lot)	$2,500	___	______
Multipoint Recorder	$5,000	___	______
Annunciator	$2,500	___	______
Control Panel & Miscellaneous Indicators	$24,165	___	______
Flame Safety System:			
Operator interface and logic unit	$24,165	___	______
Gas Safety valves	$6,041	___	______
Oil Safety valves	$6,041	___	______
Fuel pressure switches	$625	___	______
Drum Level Hi/Lo & Lo Cutoff switches	$1,125	___	______
Miscellaneous Other Unit Instrument Costs:			
	SUBTOTAL:		______

HEATING PLANT CONTROLS UPGRADE PROPOSAL
PART 3 LARGE UNIT COST ESTIMATE (One per Boiler)

ITEM	UNIT COST	QTY	COST EST
FD Fan Damper Drive	$15,235	___	______
Control Valves:			
Feed water	$10,882	___	______
Gas	$10,882	___	______
Oil	$10,882	___	______
Transmitters:			
Drum Level (two)	$1,250	___	______
Drum Pressure	$1,125	___	______
Steam Pressure	$1,125	___	______
Flow Meters:			
Feedwater	$2,500	___	______
Steam	$2,500	___	______
Gas	$2,500	___	______
Oil	$2,500	___	______
Oxygen Analyzer	$11,875	___	______
Controllers:			
Steam Pressure	$2,500	___	______
Gas	$2,500	___	______
Oil	$2,500	___	______
Drum Level	$2,500	___	______
Air Flow	$2,500	___	______
Oxygen Trim	$2,500	___	______
Temperature Elements (RTDs or Thermalcouples)	$2,500	___	______
Multipoint Recorder	$2,500	___	______
Pressure & Temperature Gages (1 lot)	$5,000	___	______
Annunciator	$2,500	___	______
Control Panel & Miscellaneous Indicators	$43,528	___	______
Flame Safety System:			
Operator interface and logic unit	$43,528	___	______
Gas Safety valves	$10,882	___	______
Oil Safety valves	$10,882	___	______
Fuel pressure switches	$625	___	______
Drum Level Hi/Lo & Lo Cutoff switches	$1,125	___	______

Miscellaneous Other Unit Instrument Costs:

SUBTOTAL: ______

HEATING PLANT CONTROLS UPGRADE PROPOSAL
PART 4 - BALANCE OF PLANT - COST ESTIMATE

ITEM	UNIT COST	QTY	COST EST
Feed Water Pump Controls	$2,500	___	_______
Condensate Controls:			
Control Valve	$3,125	___	_______
Level Transmitter	$1,250	___	_______
Level Controller	$2,500	___	_______
Hi & Lo Level Switches	$1,125	___	_______
Deaerator Instruments & Controls:			
Level Control Valve	$3,125	___	_______
Temperature Transmitter	$750	___	_______
Pressure Transmitter	$1,125	___	_______
Level Transmitter	$1,250	___	_______
Level Controller	$2,500	___	_______
Hi and Low Level Switches	$1,125	___	_______
Pressure Reducing Stations:			
Control Valve	$3,750	___	_______
Pressure Transmitter	$1,125	___	_______
Pressure Controller	$2,500	___	_______
Fuel Oil Storage & Handling Controls:			
Tank Levels and Spills	$2,500	___	_______
Pump Controls	$1,250	___	_______
Other Miscellaneous Monitoring Points:			
Pollution Control Equipment (per point)	$250	___	_______
Emission Monitoring (per point)	$250	___	_______
Plant Electrical (per point)	$250	___	_______
Air Compressors (per point)	$250	___	_______
Water Treatment (per point)	$250	___	_______
Personal Computer Monitoring System:			
Personal Computer & Software	$12,500	___	_______
Systems Integration (per point)	$188	___	_______
Commissioning (per point or control loop)	$125	___	_______
Control Room (____sq ft * $100/sq ft)	$100	___	_______
Miscellaneous Other Unit Instrument Costs:			
SUBTOTAL - Balance of Plant:			_______

HEATING PLANT CONTROLS UPGRADE PROPOSAL

PART 5 SUMMARY

Location & Plant: ___________

Date: ___________

UNIT COSTS

Unit #	Annual Savings (From Part II)	Unit Costs (From Part III)
____	$________	$________
____	$________	$________
____	$________	$________
____	$________	$________
____	$________	$________
____	$________	$________
____	$________	$________
____	$________	$________

$____________ Unit Subtotal — Line 1

PLANT COSTS (from PART 4) $____________ Balance of Plant — Line 2

Total Cost $____________ (Line 1 + Line 2) — Line 3

TOTALS: $______________ Total Annual Savings X 5.747 K_{PWF} (Present Worth Factor) (1) = $____________ Savings (PW) — Line 4

NET Savings (Cost) $____________ (Line 4 - Line 3) — Line 5

(1) K_{PWF} = Present Worth Factor (answer 5.747 based on 8 years at 8 percent interest).

Appendix D: Sample Proposal

HEATING PLANT CONTROLS UPGRADE PROPOSAL
PART 1 PLANT DESCRIPTION

Plant & Location: USA SAMPLE
Date: 7/16/93

UNIT DATA

	SIZE	PRESS	FUEL	EXISTING CONTROLS[1]	INSTALL DATE	DATE of LAST OVERHAUL	MECHANICAL CONDITION[2]	EXIT FLUE GAS TEMPERATURE
Unit No. 1	15K	150	GAS	Bailey Pneumatic	1965	1991	Good	355°F
Unit No.								
Unit No.								
Unit No.								
Unit No.								
Unit No.								

SERVICE REQUIREMENTS - Briefly describe types of loads served (size, variability, criticality, expected future load changes, environmental constraints, etc.)

Attach supplemental documents as necessary to address these questions
1. Controls Manufacturer and Model Number.
2. List any known mechanical deficiencies such as burners, excessive air infiltration, boiler tube failure, fan problems, etc.

HEATING PLANT CONTROLS UPGRADE PROPOSAL
PART 2 BENEFITS

(Submit one sheet per boiler and per fuel if dual fired)

Boiler# 1

Fuel# 1 (gas, oil, other ______________) circle one

Location & Plant: USA SAMPAL

Date: 7/16/93

POTENTIAL UNIT ENERGY SAVINGS calculations are listed by column number, in footnotes, below.

Load Range	(1) Average Load Fraction	(2) Operating Hours Per Year	(3) Maximum Capacity MBTU/HR	(4) Fuel Cost $/MBTU	(5) Fuel Cost $/Year	(6) Actual % O_2	(7) Target %O_2	(8) Δ %O_2	(9) Approximate % Efficiency Improvement
10-40%	0.25	1000	20	3.5	17,500	10	6	4	0.57
40-60%	0.50	2000	20	3.5	70,000	10	4	6	1.71
60-85%	0.725	3000	20	3.5	152,250	6	1.5	4.5	1.93
85-100%	0.925	1000	20	3.5	64,750	6	1.5	4.5	0.64
Annual Total Hrs.(2T)		7000 (Max 8760)	Total Annual Fuel Cost(5T)		$304,500		% Efficiency Improvement(9T)		4.86

Notes: Calculations for columns (by column number):

(2T) = Sum of column (2) = Operating Hours Per Year
(5) = (1) x (2) x (3) x (4) = Fuel Cost $/Yr
(5T) = Sum of column (5) = Total Annual Fuel Cost
(8) = (6) - (7) = %O_2 improvement
(9) = (2) + (2T) x (8) = Approximate Efficiency Improvement
(9T) = Sum of column (9) = % Efficiency Improvement
(10) = (5T) x (9T) + 100 = Cost Savings
(11) = (10) + (4) = Potential Energy Savings

Cost Savings(10) $ 14,790

Energy Savings(11) 4226 (MBTU/Year)

MAINTENANCE HISTORY - Briefly describe control systems maintenance activity, spare parts availability, manufacturer support, etc.)

SAFETY - Briefly describe any known safety issues such as compliance with current codes.

FUTURE CONTROL SYSTEM - Briefly describe features of control system envisioned.

Attach additional supporting information as necessary.

HEATING PLANT CONTROLS UPGRADE PROPOSAL
PART 3 SMALL UNIT COST ESTIMATE (One per Boiler)

ITEM	UNIT COST	QTY	COST EST
Jack Shaft Drive Unit	$4,375	1	$4,375
Control Valves:			
Feed water	$3,125	0	$0
Gas	$3,125	1	$3,125
Oil	$3,125	0	$0
Transmitters:			
Drum Level	$1,250	1	$1,250
Steam Pressure	$1,125	1	$1,125
Flow Meters:			
Feedwater	$2,500	1	$2,500
Steam	$2,500	1	$2,500
Gas	$2,500	1	$2,500
Oil	$2,500	0	$0
Oxygen Analyzer & Controller (see Note 1)	$9,375	1	$9,375
Controllers:			
Steam Pressure	$2,500	1	$2,500
Drum Level	$2,500	1	$2,500
Pressure & Temperature Gages (1 lot)	$2,500	1	$2,500
Multipoint Recorder	$2,500	1	$2,500
Annunciator	$2,500	1	$2,500
Control Panel & Miscellaneous Indicators	$12,500	1	$12,500
Flame Safety System:			
Operator interface and logic unit	$12,500	0	$0
Gas Safety valves	$3,125	0	$0
Oil Safety valves	$3,125	0	$0
Fuel pressure switches	$625	0	$0
Drum Level Hi/Lo & Lo Cutoff switches	$1,125	0	$0
Miscellaneous Other Unit Instrument Costs:			
	SUBTOTAL:		$51,750

Note 1: Oxygen trim is optional depending on potential economic benefit.

HEATING PLANT CONTROLS UPGRADE PROPOSAL
PART 4 - BALANCE OF PLANT - COST ESTIMATE

ITEM	UNIT COST	QTY	COST EST
Feed Water Pump Controls	$2,500	0	$0
Condensate Controls:			
Control Valve	$3,125	0	$0
Level Transmitter	$1,250	0	$0
Level Controller	$2,500	0	$0
Hi & Lo Level Switches	$1,125	0	$0
Deaerator Instruments & Controls:			
Level Control Valve	$3,125	0	$0
Temperature Transmitter	$750	0	$0
Pressure Transmitter	$1,125	0	$0
Level Transmitter	$1,250	0	$0
Level Controller	$2,500	0	$0
Hi and Low Level Switches	$1,125	0	$0
Pressure Reducing Stations:			
Control Valve	$3,750	0	$0
Pressure Transmitter	$1,125	0	$0
Pressure Controller	$2,500	0	$0
Fuel Oil Storage & Handling Controls:			
Tank Levels and Spills	$2,500	0	$0
Pump Controls	$1,250	0	$0
Other Miscellaneous Monitoring Points:			
Pollution Control Equipment (per point)	$250	4	$1,000
Emission Monitoring (per point)	$250	3	$750
Plant Electrical (per point)	$250	6	$1,500
Air Compressors (per point)	$250	1	$250
Water Treatment (per point)	$250	1	$250
Personal Computer Monitoring System:			
Personal Computer & Software	$12,500	1	$12,500
Systems Integration (per point)	$188	60	$11,250
Commissioning (per point or control loop)	$125	90	$11,250
Control Room (_____sq ft * $100/sq ft)	$100	0	$0
Miscellaneous Other Unit Instrument Costs:			$_______
SUBTOTAL - Balance of Plant:			$38,750

HEATING PLANT CONTROLS UPGRADE PROPOSAL

PART 5 SUMMARY

Location & Plant: ____________
Date: ____________

UNIT COSTS

Unit #	Annual Savings (From Part II)	Unit Costs (From Part III)
1	$14,790	$51,750
___	$________	$________
___	$________	$________
___	$________	$________
___	$________	$________
___	$________	$________
___	$________	$________
___	$________	$________

$51,750 Unit Subtotal — Line 1

PLANT COSTS (from PART 4) $38,750 Balance of Plant — Line 2

Total Cost $90,500 (Line 1 + Line 2) — Line 3

TOTALS: $14,790 Total Annual Savings X 5.747 K_{PWF} (Present Worth Factor) (1) = $84,998 Savings (PW) — Line 4

NET Savings (Cost) $(5,501) (Line 4 - Line 3) — Line 5

(1) K_{PWF} = Present Worth Factor (answer 5.747 based on 8 years at 8 percent interest).

Appendix E: Typical Design Tasks

A boiler control system upgrade project should be carried out in a systematic manner. The following suggested task list can be tailored to the specific project and used as a checklist during the project:

1. Assemble basic plant data to support proposal development:

   a. Number of boilers in central heat plant.

   b. List design conditions: Steam generation (pph), steam pressure (psig), and steam temperature (°F).

   c. Fuel type: Natural gas, oil, or combination.

   d. Furnace: Indicate if positive of vacuum pressure, forced draft, induced draft, or balanced draft.

   e. Boiler heat recovery equipment: List if boiler system includes an air heater, economizer, etc.

   f. Boiler manufacturer, model, date placed in service, and dates of major improvements.

   g. Identify burner: Manufacturer, model, maximum firing rate (Btu/h), and turndown.

   h. Service: Describe steam usage (heating, process, power). Define load swings encountered, i.e., how much demand changes in what time frame.

   i. Operating conditions: Determine yearly operating ranges for steam production, pressure, and temperature. Determine in-service hours per year. Use data from last 3 years if possible.

   j. Thermal efficiency: Obtain, test (if necessary), boiler efficiency (in accordance with ASME PTC 4.1).

   k. Fuel cost: Obtain average fuel cost at plant.

   l. Savings potential: Review present thermal efficiency of boiler. Examine indices of combustion and thermal performance such as excess oxygen and exit flue gas temperature. Minimizing the excess oxygen level in the flue along with decreasing the exit flue temperature will promote optimal operation and save on operating costs as a result of lower fuel bills. Generally, a boiler in good mechanical condition, well tuned and properly instrumented, should have as a reasonable target 3.0 percent (oil) to 1.5 percent (gas) excess oxygen and a stack temperature not exceeding the steam outlet temperature by more than 150 °F.

Actual permissible levels of oxygen in the flue is limited and dependent on combustion variables like CO concentration (usually 300-400 ppm), opacity, unburned carbon and NO_X levels. Reduction of the stack gas temperature is also limited. Flue gas temperature must be kept high enough to provide the proper stack effect, and such that condensation does not take place.

2. Assemble basic instrumentation data:

   a. Type: Determine if instruments are pneumatic, electronic (analog), or electronic (microprocessor-based).

   b. Analog inputs: Summarize primary sensors measuring flow, pressure, temperature, level, and analysis. List service, manufacturer, model, signal (i.e., 3-15 psig, 4-20 ma), Engineering range (i.e., 0-100 psig), physical condition, and approximate installation date.

   c. Analog outputs: Summarize the analog output actuators for their similar properties.

   d. Discrete I/O: Summarize the discrete (on-off) devices.

3. Assemble basic functional control descriptions:

   a. Burner Management Safety: These devices, if activated, will shut down the boiler. Determine boiler interlocks, verify compliance with current NFPA 85.

   b. Regulatory: Proportional and throttling control. Identify control loops and examine performance levels.

4. Examine Cost Considerations:

   a. Determine cost justification for automation work. Calculate yearly fuel savings along with other potential savings. Assume a 3-year direct payback period to obtain a budgetary cost allowed for automation work.

   b. Control work required based on antiquated, nonrepairable hardware should be justified on its own merits.

   c. Examine long range goals and benefits such as improved safety, reliability, and robustness.

5. Determine scope of upgraded controls, and set objectives based on budget and plant goals, for example:

   a. Automate the boiler regulatory control functions for feed water/drum level control and combustion/excess air trim control, to ensure steam production to match the plants needs while maintaining steam pressure, steam temperature, drum level, and excess air at safe acceptable limits.

b. Provide sequential control functions to implement burner management for automatic start-up, shutdown, and emergency boiler shutdown.

c. Provide safety interlock logic to monitor boiler operation to ensure that safe limits are maintained. Execute emergency shutdown action should these limits be exceeded in manual or automatic operation.

6. Determine control strategy to achieve stated objective. Describe logic via functional diagrams using SAMA symbols.

7. Based on extent of upgrade, determine field instrumentation needs for new replacement transmitters.

8. Determine system size, total all digital and analog I/O in central heat plant. Maintain separate logic equipment for combustion control and flame safety systems.

9. Develop a procurement specification (or Request for Proposal) describing required features, equipment, and services. Incorporate sufficient detail performance requirements on which to base subsequent proposal evaluation.

10. Issue for bids.

11. Review design features of proposal automation package in the following areas:

   - I/O handling: signal types, accuracy of analog to digital conversion.
   - Processor capability: scan times, number of PID loops, redundancy, operating system (proprietary or nonproprietary).
   - Networking: types, speed, maximum number of devices, distances.
   - Data base: type, support SQL language.
   - Operating system: proprietary, MS DOS, UNIX.
   - Operator interface: single loop, workstation or real-time PC.
   - Trending capabilities: real-time and historical.
   - Alarm management: priority levels.
   - Report generation.
   - Custom graphics display.

12. Sample documents created during design or prior to equipment assembly.

13. Factory Demonstration Test to witness assembled equipment, software performance, graphics and reports.

14. O&M Manual

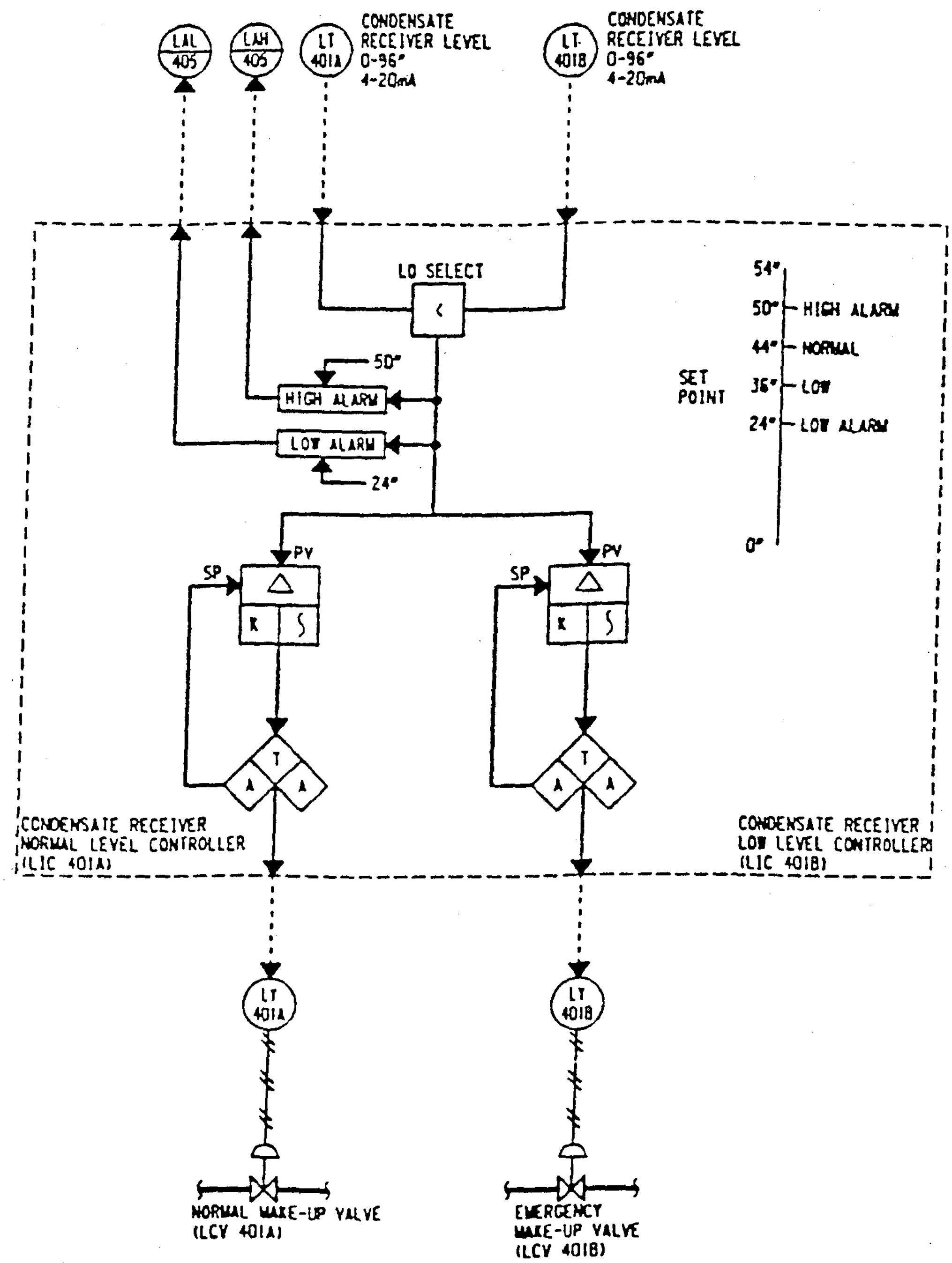
15. Training

16. Commissioning, start-up, and acceptance.

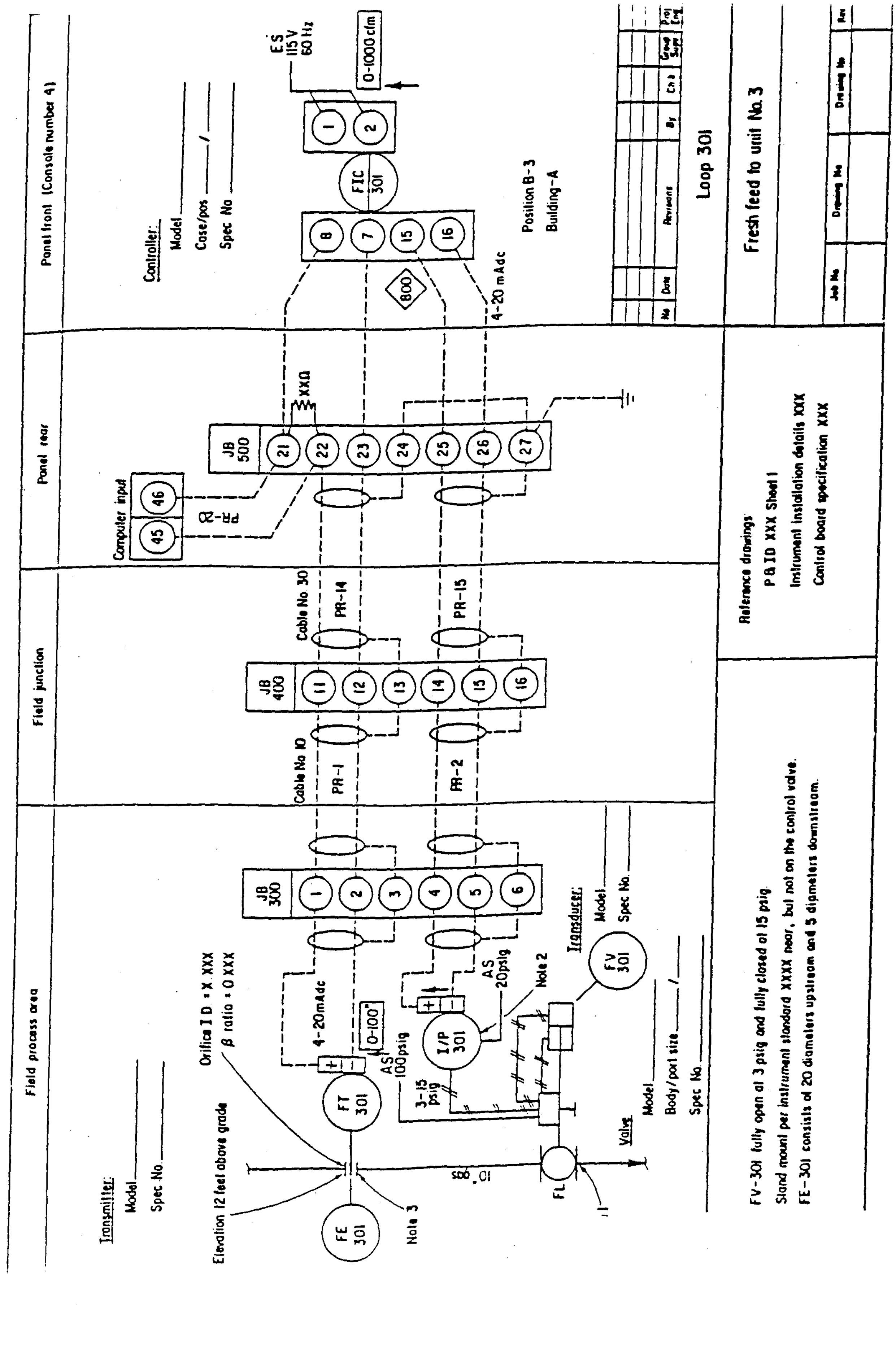
17. "As-Built" or record documentation for plant maintenance.

Appendix F: Sample Design Documents

SAMA Diagram



Loop Diagram



Instrument Index

PRIMARY TAG NO.		SERVICE	DESCRIPTION	SUPPLIED BY	DATA SHEET
PIC	000	STEAM MASTER	INDICATING CONTROLLER	0	1000.0-01
UA	000	STEAM DISTRIBUTION ALARMS	ANNUNCIATOR	0	
UR	000	STEAM MASTER	RECORDER	0	865.0-01
FE	001	BOILER FEED PUMP NO. 1 MIN. FLOW ORIFICE	ORIFICE	3	285.0-01
HS	001	BOILER FEED PUMP NO. 1 START/STOP	SELECTOR SWITCH	4	
PI	001	BOILER FEED PUMP NO. 1 PRESSURE	PRESSURE GAGE	3	411.4-01
XL	001	BOILER FEED PUMP NO. 1 RUN/OFF	PILOT LIGHT	4	
FE	002	BOILER FEED PUMP NO. 2 MIN. FLOW ORIFICE	ORIFICE	3	285.0-02
HS	002	BOILER FEED PUMP NO. 2 START/STOP	SELECTOR SWITCH	4	
PI	002	BOILER FEED PUMP NO. 2 PRESSURE	PRESSURE GAGE	3	411.4-01
XL	002	BOILER FEED PUMP NO. 2 RUN/OFF	PILOT LIGHT	4	
FE	003	BOILER FEED PUMP NO. 3 MIN. FLOW ORIFICE	ORIFICE	3	285.0-03
HS	003	BOILER FEED PUMP NO. 3 START/STOP	SELECTOR SWITCH	4	
PI	003	BOILER FEED PUMP NO. 3 PRESSURE	PRESSURE GAGE	3	411.4-01
XL	003	BOILER FEED PUMP NO. 3 RUN/OFF	PILOT LIGHT	4	
PI	005	FEEDWATER PRESSURE	DIGITAL INDICATOR	4	
PSL	005	FEED WATER HEADER PRESSURE LOW.	PRESSURE SWITCH	3	420.1-01
PT	005	FEEDWATER HEADER PRESSURE	PRESSURE TRANSMITTER	0	
TE	006	FEEDWATER HEADER TEMPERATURE	TEMPERATURE ELEMENT	3	613.0-01
TT	006	FEEDWATER HEADER TEMPERATURE	TEMPERATURE TRANSMITTER	0	
PCV	009	FEEDWATER SUPPLY TO DESUPERHEATER	PRESSURE CONTROL VALVE	3	
HS	031	FUEL OIL PUMP NO. 1 START/STOP/AUTO	SELECTOR SWITCH	4	
XL	031	FUEL OIL PUMP NO. 1 RUN/OFF	PILOT LIGHT	4	
HS	032	FUEL OIL PUMP NO. 2 START/STOP/AUTO	SELECTOR SWITCH	4	
XL	032	FUEL OIL PUMP NO. 2 RUN/OFF	PILOT LIGHT	4	
HS	033	POWER PLANT DAY TANK PMP START/STOP/AUTO	SELECTOR SWITCH	4	
XL	033	POWER PLANT DAY TANK PUMP RUN/OFF	PILOT LIGHT	4	
PI	034	FUEL OIL HEADER PRESSURE	PRESSURE GAGE	3	411.4-01
PCV	035	FUEL OIL RECIRCULATION	PRESSURE CONTROL VALVE	3	756.0-01
PT	055	250 # STEAM HEADER PRESSURE	PRESSURE TRANSMITTER	0	
TE	056	250 # STEAM HEADER TEMPERATURE	TEMPERATURE ELEMENT	3	613.0-01
TT	056	250 # STEAM HEADER TEMPERATURE	TEMPERATURE TRANSMITTER	0	
PI	060	120 # STEAM HEADER PRESSURE	INDICATOR	4	
PT	060	120 # STEAM HEADER PRESSURE	PRESSURE TRANSMITTER	0	
PCV	061A	250 # TO 120 # STEAM PRESSURE REDUCTION	PRESSURE CONTROL VALVE	3	700.1-01
PIC	061A	250 # TO 120 # STEAM PRESSURE REDUCTION	PRESSURE INDICATING CONTROLLER	3	1003.4-01
PCV	061B	250 # TO 120 # STEAM PRESSURE REDUCTION	PRESSURE CONTROL VALVE	3	700.1-02
PIC	061B	250 # TO 120 # STEAM PRESSURE REDUCTION	PRESSURE INDICATING CONTROLLER	3	1003.4-02
PCV	061C	250 # TO 120 # STEAM PRESSURE REDUCTION	PRESSURE CONTROL VALVE	3	700.1-03
PIC	061C	250 # TO 120 # STEAM PRESSURE REDUCTION	PRESSURE INDICATING CONTROLLER	3	1003.4-03
PRV	062	120 # STEAM PRESSURE	PRESSURE RELIEF VALVE	3	
PI	070	60 # STEAM HEADER PRESSURE	INDICATOR	4	
PT	070	60 # STEAM HEADER PRESSURE	PRESSURE TRANSMITTER	3	400.1-01
PCV	071A	120 # TO 60 # STEAM PRESSURE REDUCTION	PRESSURE CONTROL VALVE	3	700.1-04
PIC	071A	120 # TO 60 # STEAM PRESSURE REDUCTION	PRESSURE INDICATING CONTROLLER	3	1003.4-04
PCV	071B	120 # TO 60 # STEAM PRESSURE REDUCTION	PRESSURE CONTROL VALVE	3	700.1-05
PIC	071B	120 # TO 60 # STEAM PRESSURE REDUCTION	PRESSURE INDICATING CONTROLLER	3	1003.4-05

Instrument Data Sheet

Prepared by
STANLEY CONSULTANTS

LEVEL INSTRUMENT
DIFFERENTIAL PRESSURE TYPE

NO.	BY	DATE	REVISION

SHEET 1 OF
SPEC. NO. 324.0
CONTRACT
SCI PROJECT NO.
BY CHK'D

	1	Tag No. LT 101	Service BOILER NO. 1 DRUM LEVEL
GENERAL	2	Function	BLIND TRANSMIT
	3	Case	MFR. STD. Color: MFR. STD.
	4	Mounting	MOUNT ON 3-VALVE MANIFOLD (NOTE 1)
	5	Enclosure Class	WEATHER PROOF
	6	Power Supply	24 VDC FROM LIC 101
	7	Chart	
	8	Chart Drive	
	9	Scale	
XMTR	10	Transmitter Output	4-20 mA
CONTROLLER	11	Control Modes	N/A
	12	Action	
	13	Auto-Man Switch	
	14	Set Point Adj.	
	15	Manual Reg.	
	16	Output	
UNIT	17	Service	LEVEL
	18	Element Type	CAPACITANCE
	19	Material	Body: LOW COPPER ALUMINUM Element: 316 SS Flange: 316 SS
	20	Rating	Overrange: 2000 PSIG Body Rating: 2000 PSIG
	21	Diff. Range	Adj. Range: 0-5 to 30" W.C. Set At: 0 - 17.226" W.C.
	22		Elevation: Suppression:
	23	Process Data	Fluid: WATER Max Temp.: 436° F Max. Pressure: 350 PSIG
	24	Process Conn.	1/2" NPT
	25	Alarm Switches	
	26	Function	
	27	Options	
	28	Mfr. & Model No.	MOORE PRODUCTS MYCRO 340D **

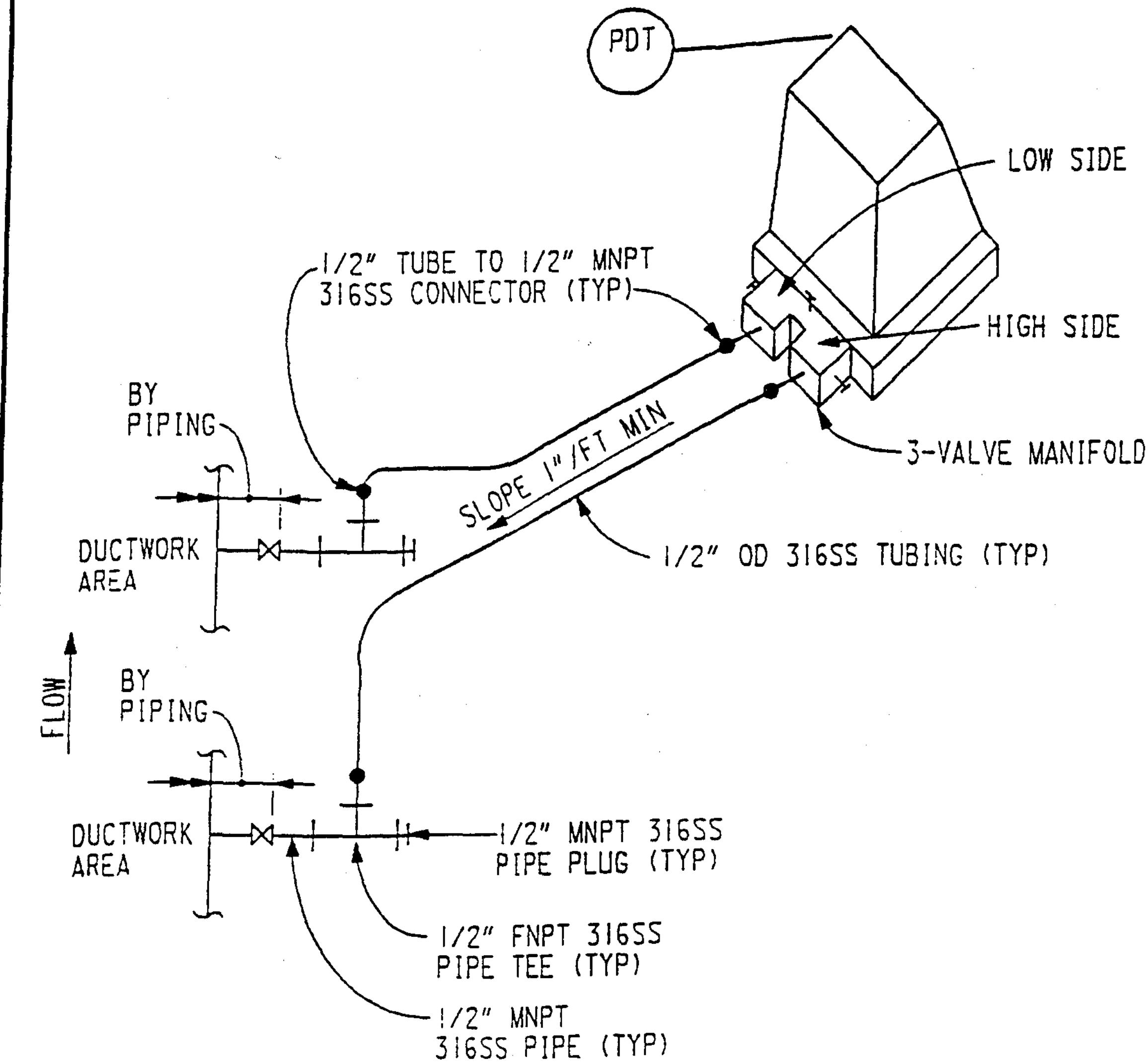
Notes:

1. PROVIDE AGCO M4TVIS-4-AM 3-VALVE MANIFOLD AND MOUNTING HARDWARE. MANIFOLD PROCESS CONNECTION IS 1/2" - 14 NPT.

** MANUFACTURER TO PROVIDE COMPLETE MODEL NUMBER.

SC

Installation Detail



NOTES:

1. MOUNT TRANSMITTER WITH INDICATOR VISIBLE TO WALKWAY, IF FURNISHED
2. FOR TRANSMITTER MOUNTING, SEE MOUNTING DETAIL IC-M-3
3. FOR CONDUIT CONNECTIONS, SEE CONDUIT CONNECTION DETAILS
4. MOUNT TRANSMITTER ABOVE PROCESS TAPS

NOT A DESIGN DOCUMENT

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